Western Gas Partners LP
Form 10-K
March 11, 2010

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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, 2009

Or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number: 001-34046

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

Delaware *(State or other jurisdiction of incorporation or organization)*	**26-1075808** *(I.R.S. Employer Identification No.)*
1201 Lake Robbins Drive **The Woodlands, Texas** *(Address of principal executive offices)*	**77380** *(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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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. o

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

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

The aggregate market value of the Partnership s common units representing limited partner interests held by non-affiliates of the registrant was approximately $316.0 million on June 30, 2009 based on the closing price as reported on the New York Stock Exchange.

At March 1, 2010, there were 36,995,614 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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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; the approximate amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

CO_2: Carbon dioxide.

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.

Imbalance: Imbalances result from (i) differences between gas volumes nominated by customers and gas volumes received from those customers and (ii) differences between gas volumes received from customers and gas volumes delivered to those customers.

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

LTD: Long tons 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. All volumes presented herein are based on a standard pressure base of 14.73 pounds per square inch, absolute.

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.

Play: A group of gas or oil fields that contain known or potential commercial amounts of petroleum and/or natural gas.

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

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Receipt point: The point where production is received by or into a gathering system, processing facility 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.

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.

WESTERN GAS PARTNERS, LP

PART I

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

GENERAL OVERVIEW

Western Gas Partners, LP is a growth-oriented Delaware master limited partnership, or MLP, organized by Anadarko Petroleum Corporation in 2008 to own, operate, acquire and develop midstream energy assets. Our common units are publicly-traded and listed on the New York Stock Exchange under the symbol WES. 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, as defined below, and other producers and customers.

Unless the context clearly indicates otherwise, references in this report to the Partnership, we, our, us or like terms, when used in the present tense or prospectively, refer to Western Gas Partners, LP and its consolidated subsidiaries. References in this report to the Partnership, we, our, us or like terms, when used in the historical context, refer to th 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 *Acquisitions-Powder River Acquisition* below, from August 23, 2006 thereafter, and combined with the financial results and operations of the Chipeta assets, as described in *Acquisitions-Chipeta Acquisition* below, from August 10, 2006 thereafter.

Anadarko refers to Anadarko Petroleum Corporation (NYSE: APC) and its consolidated subsidiaries, excluding the Partnership and Western Gas Holdings, LLC, our general partner. Parent refers to Anadarko prior to our acquisition of assets from Anadarko. Affiliates refers to wholly owned and partially owned subsidiaries of Anadarko, excluding the Partnership. 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, MIGC refers to MIGC LLC and Chipeta refers to Chipeta Processing LLC. Each of AGC, PGT, MIGC, Chipeta, our general partner and the Partnership is an indirect subsidiary of Anadarko.

Based on throughput for the year ended December 31, 2009, approximately 98% of our services are provided under long-term contracts with fee-based rates and approximately 2% of our services are provided under percent-of-proceeds contracts. 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.

We believe that one of our principal strengths is our relationship with Anadarko. Over 79% of our total natural gas gathering, processing and transportation throughput was comprised of natural gas production owned or controlled by Anadarko during the year ended December 31, 2009. In addition and solely with respect to the gathering systems connected to our initial assets, Anadarko has dedicated to us all of the natural gas production it owns or controls from (i) wells that are currently connected to such gathering systems, and (ii) additional wells that are drilled within one mile of wells connected to these gathering systems, as those 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 these gathering systems.

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*. The public 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. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The public 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.

OUR ASSETS AND AREAS OF OPERATION

As of December 31, 2009, our assets consist of nine gathering systems, six natural gas treating facilities, four gas processing facilities, one NGL pipeline 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 and the Mid-Continent. The following table provides information regarding our assets by geographic region as of or for the year ended December 31, 2009:

Area	**Asset Type**	**Miles of Pipelines**	**Approximate Number of Receipt Points**	**Gas Compression (Horsepower)**	**Processing or Treating Capacity (MMcf/d)**	**Average Gathering, Processing and Transportation Throughput (MMcf/d)**
East Texas	Gathering and Treating	589	827	44,855	502	389
West Texas	Gathering	116	90	560		154
Rocky Mountains	Gathering and Treating(1)	428	179	25,839	387	175
	Gathering and Processing(2)	1,350	699	88,838	703	395
	Transportation	256	16	29,696		165
Mid-Continent	Gathering	2,034	1,536	102,257		121
Total		4,773	3,347	292,045	1,592	1,399

(1) Throughput includes the Partnership s 14.81% share of Fort Union Gas Gathering, L.L.C. s gross volumes.

(2) Throughput consists of 100% of Chipeta and Hilight plant volumes and 50% of Newcastle plant volumes.

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.

RECENT DEVELOPMENTS

Revolving Credit Facility. In October 2009, we entered into a three-year senior unsecured revolving credit facility with aggregate initial commitments of $350.0 million, which can be expanded to a maximum of $450.0 million. This revolving credit facility matures on October 29, 2012 and bears interest at the applicable London Interbank Offered Rate, or LIBOR, plus applicable margins ranging from 2.375% to 3.250%. We are also required to pay a quarterly facility fee ranging from 0.375% to 0.750% of the commitment amount (whether used or unused), based upon our consolidated leverage ratio, as defined in the revolving credit facility.

2009 Equity Offering. On December 9, 2009, we closed a public offering of 6,000,000 common units at a price of $18.20 per unit. On December 17, 2009, we issued an additional 900,000 common units to the public pursuant to the full exercise of the underwriters over-allotment option granted in connection with that offering. We refer to the December 9 and December 17, 2009 issuances collectively as the 2009 equity offering. Net proceeds from the offering of approximately $122.5 million were used to repay $100.0 million outstanding under our revolving credit facility and to partially fund the Granger acquisition in January 2010.

See *Note 13 Subsequent Events Granger acquisition* of the notes to the consolidated financial statements under *Item 8* of this annual report.

ACQUISITIONS

We have made the following acquisitions from Anadarko:

Initial Assets Acquisition. 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. The May 14 and June 11, 2008 issuances are referred to collectively as the initial public offering. Concurrent with the May 2008 closing of our initial public offering, Anadarko contributed the assets and liabilities of AGC, PGT, and MIGC to us in exchange for a 2.0% general partner interest in the Partnership, 5,725,431 common units, 26,536,306 subordinated units and 100% of the incentive distribution rights, or IDRs. We refer to AGC, PGT and MIGC as our initial assets.

Powder River Acquisition. In December 2008, we acquired certain midstream assets from Anadarko, consisting 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., or Fort Union. We refer to these assets collectively as the Powder River assets and to the acquisition as the Powder River acquisition. The Powder River assets provide a combination of gathering, treating and processing services in the Powder River Basin of Wyoming.

Chipeta Acquisition. In July 2009, we acquired a 51% membership interest in Chipeta, together with an associated NGL pipeline, from Anadarko. Chipeta owns a natural gas processing plant complex, which includes two processing trains: a refrigeration unit completed in November 2007 with a design capacity of 240 MMcf/d and a 250 MMcf/d capacity cryogenic unit which was completed in April 2009. We refer to the 51% membership interest in Chipeta and associated NGL pipeline collectively as the Chipeta assets and the acquisition is referred to as the Chipeta acquisition. In November 2009, Chipeta closed its $9.1 million acquisition from a third party of a compressor station and processing plant, or the Natural Buttes plant, which was known as the CIG 101 plant prior to the acquisition. The Natural Buttes plant is located in Uintah County, Utah and provides up to 180 MMcf/d of incremental refrigeration processing capacity.

Granger Acquisition. In January 2010, we acquired the following assets from Anadarko: (i) the Granger gathering system, a 750-mile gathering system with related compressors and other facilities, and (ii) the Granger complex, consisting of two cryogenic trains with combined capacity of 200 MMcf/d, two refrigeration trains with combined capacity of 145 MMcf/d, an NGLs fractionation facility with capacity of 9,500 barrels per day, and ancillary equipment. We refer to these assets collectively as the Granger assets and to the acquisition as the Granger acquisition. In connection with the acquisition, we entered into five-year, fixed-price commodity swap agreements with Anadarko which cover non-fee-based volumes processed at the Granger complex. The Granger acquisition was financed with $210.0 million of borrowings under the Partnership s revolving credit facility plus $31.7 million of cash on hand, as well as through the issuance of 620,689 common units to Anadarko and 12,667 general partner units to our general partner. See *Note 13 Subsequent Events Granger acquisition* of the notes to the consolidated financial statements under *Item 8* of this annual report.

Presentation of Partnership Acquisitions. For purposes of this annual report, the assets in which we owned an interest as of December 31, 2009, which consist of the initial assets, Powder River assets and Chipeta assets, are referred to collectively as the Partnership Assets. References to periods prior to our acquisition of the Partnership Assets and similar phrases refer to periods prior to May 14, 2008, with respect to the initial assets, periods prior to December 19, 2008, with respect to the Powder River assets, and periods prior to July 1, 2009, with respect to the Chipeta assets. Reference to periods including and subsequent to our acquisition of the Partnership Assets and similar phrases refer to periods including and subsequent to May 14, 2008, with respect to the initial assets, periods including and subsequent to December 19, 2008, with respect to the Powder River assets, and periods including and subsequent to July 1, 2009, with respect to the Chipeta assets.

Because Anadarko owns our general partner, each acquisition of Partnership Assets, except for the Natural Buttes plant, was considered a transfer of net assets between entities under common control. As a result, after each acquisition of significant assets from Anadarko, we are required to revise our financial statements to include the activities of those assets as of the date of common control. Our historical financial statements for the years ended December 31, 2008 and December 31, 2007 as presented in our annual report on Form 10-K for the year ended December 31, 2008, which included the results attributable to the Powder River assets, have been recast to reflect the results attributable to the Chipeta assets as if the Partnership owned the 51% interest in Chipeta and associated midstream assets for all periods presented.

STRATEGY

Our primary business objective is to continue 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, compression, treating, processing and transportation needs that result from their drilling activity in our areas of operation.

Attracting third-party volumes to our systems. We expect to continue actively marketing our midstream services to, and pursuing strategic relationships with, third-party producers with the intention of attracting additional volumes and/or expansion opportunities.

Minimizing commodity price exposure. We intend to continue to limit our direct exposure to commodity price changes. 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 and keep-whole contracts.

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, as of December 31, 2009, a 54.8% 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 and keep-whole 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. As of December 31, 2009, we had $350.0 million of borrowing capacity available to us under our revolving credit facility, $100.0 million of borrowing capacity available to us under Anadarko s $1.3 billion revolving credit facility and a

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$30.0 million working capital facility with Anadarko. In December 2009, we raised $122.5 million of net proceeds through our first follow-on equity offering. On January 29, 2010, we borrowed $210.0 million under our revolving credit facility to partially fund the acquisition of the Granger assets from Anadarko. 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 our strategy across capital-market cycles.

Prudent capital management. Our asset portfolio currently has relatively low capital expenditure requirements. Total capital expenditures for the years ended December 31, 2009 and 2008 were $62.2 million and $99.5 million, respectively, including approximately $30.8 million and $55.1 million, respectively, of expansion capital expenditures for the Chipeta assets prior to our acquisition of the assets. For the years ended December 31, 2009 and 2008, our maintenance capital expenditures, including 51% of Chipeta s expenditures, were $15.9 million and $17.5 million, respectively.

Experienced management team. Members of our general partner s management team have extensive experience in building, acquiring, integrating, financing and managing midstream assets. Since our initial public offering, we have expanded our executive management team to include Donald R. Sinclair, President and Chief Executive Officer, and Benjamin M. Fink, Senior Vice President and Chief Financial Officer. Our relationship with Anadarko also 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* of this annual report

OUR RELATIONSHIP WITH ANADARKO PETROLEUM CORPORATION

One of our principal strengths is our relationship with Anadarko. Our operations and activities are managed by our general partner, which is a wholly owned subsidiary of Anadarko. Anadarko Petroleum Corporation is among the largest independent oil and gas exploration and production companies in the world. Anadarko s upstream oil and gas business explores for and produces natural gas, crude oil, condensate and natural gas liquids, or NGLs. 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, 2009, Anadarko indirectly held 1,283,903 general partner units representing a 2.0% general partner interest in the Partnership and 100% of the Partnership IDRs through its ownership of our general partner, and 8,633,746 common units and 26,536,306 subordinated units, which comprise an aggregate 54.8% limited partner interest in the Partnership. The public held 27,741,179 common units, representing a 43.2% limited partner interest in the Partnership.

In connection with our initial public offering, 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 we believe 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, construct or participate in the ownership of 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 (or be able) to pursue any such opportunities. Please see *Item 1A* and *Item 13* of this annual report for more information.

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, CO_2 and/or hydrogen sulfide, such natural gas is dehydrated to remove the saturated water and treated to separate the CO_2 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. Processing removes 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.

Storage, Transportation and Marketing. Once the raw natural gas has been treated or processed and the raw NGLs mix has been 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. We do not currently offer storage services or conduct marketing activities.

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Typical Contractual Arrangements. Midstream natural gas services, other than transportation, 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 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.

Interruptible. Interruptible transportation 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. 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.

See *Note 2 Summary of Significant Accounting Policies* of the notes to the consolidated financial statements included under *Item 8* of this annual report for information regarding our contracts.

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PROPERTIES

As of December 31, 2009, our assets consist of nine gathering systems, six natural gas treating facilities, four gas processing facilities, one NGL pipeline and one interstate pipeline. Our assets are located in East and West Texas, the Rocky Mountains and the Mid-Continent. 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 pounds per square inch, absolute.

The following map depicts our significant midstream assets as of December 31, 2009.

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East Texas

Dew gathering system. The 323-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. The Dew gathering system has 11 compressor stations with a combined 43,515 horsepower of compression.

Customers. Anadarko is the only shipper on the Dew gathering system.

Supply. As of December 31, 2009*,* Anadarko has approximately 837 producing wells in the Bossier play and controls approximately 185,000 gross acres in the area.

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.

Pinnacle gathering system. The Pinnacle gathering system includes our 266-mile Pinnacle gathering system and our Bethel treating plant. The Pinnacle system provides sour gas gathering and treating service in Anderson, Freestone, Leon, Limestone and Robertson Counties of East Texas. The Bethel treating plant, located in Anderson County, has total CO_2 treating capacity of 502 MMcf/d and 20 long tons per day, or LTD, of sulfur treating capacity.

Customers. Anadarko is the largest shipper on the Pinnacle gathering system with 198 MMcf/d for the year ended December 31, 2009, which represented approximately 88% of the total throughput on the system during such period. Approximately 10% of throughput on the system during 2009 was primarily from two third-party shippers.

Supply. The Pinnacle gathering system is well positioned to provide gathering and treating services to the five-county area over which it extends, including the Cotton Valley Lime formations, which contain relatively high concentrations of sulfur and CO_2. We expanded the Bethel treating facilities based on dedicated demand from a third party 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.

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.

Rocky Mountains

Chipeta processing plant. We own a 51% membership interest in and are the managing member of Chipeta. Chipeta is a limited liability company owned by the Partnership (51.0%), Ute Energy Midstream Holdings LLC (25.0%) and Anadarko (24.0%). Chipeta owns a natural gas processing plant complex, which includes two processing trains: a refrigeration unit completed in November 2007 with a design capacity of 240 MMcf/d and a 250 MMcf/d capacity cryogenic unit which was completed in April 2009. The Chipeta system also includes the Natural Buttes plant, which provides up to 180 MMcf/d of incremental refrigeration processing capacity, and a 100% Partnership-owned 15-mile NGL pipeline connecting the Chipeta plant to a third-party pipeline. These assets provide processing and transportation services in the Greater Natural Buttes area in Uintah County, Utah.

Customers. Anadarko is the largest customer on the Chipeta system with 338 MMcf/d throughput for the year ended December 31, 2009, which represented approximately 92% of the total throughput on the system. The balance of throughput on the system during 2009 was from two third-party customers.

Supply. The Chipeta system is well positioned to access Anadarko s and third-parties production in the area with excess available capacity and as the only cryogenic processing facility in the Uintah Basin.

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Anadarko controls approximately 237,000 gross acres in the Uintah Basin. Chipeta is connected to both Anadarko s Natural Buttes Gathering System and to the Three Rivers Gathering system owned by Ute Energy and a third party.

Delivery Points. The Chipeta plant delivers NGLs through our 15-mile pipeline to Enterprise s Mid-America Pipeline, which provides transportation through the Seminole pipeline in West Texas and ultimately to the NGL markets at Mont Belvieu, Texas and the Texas Gulf Coast. The Chipeta plant delivers natural gas through:

Questar Gas Management s pipeline to the Kern River market;

Colorado Interstate Gas Company s, or CIG s pipeline to the Opal market;

CIG s pipeline at the Annabuttes interconnect point on the Uintah Basin lateral;

Wyoming Interstate Co. s Kanda lateral pipeline with either access to the Trailblazer system or delivery to the Northwest Pipeline or the Rockies Express Pipeline; or

Questar Pipeline Company s pipeline with interconnects with Kern River at the Goshen point.

MIGC transportation system. The MIGC system is a 256-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 to Glenrock, Wyoming. As a result, the MIGC system is well positioned to provide transportation for the extensive 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. MIGC is certificated for 175 MMcf/d of firm transportation capacity, all of which is fully subscribed as of December 31, 2009.

Customers. Anadarko is the largest firm shipper on the MIGC system, with approximately 93% of throughput for the year ended December 31, 2009. For the year ended December 31, 2009, the remaining throughput on the system was from four third-party shippers.

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. In addition to its certificated forward haul capacity, MIGC additionally provides firm backhaul service subject to flowing capacity. MIGC currently has 15 MMcf/d of firm backhaul service contracted through May 2010. Most of our interruptible gas transportation agreements are month-to-month with the remainder generally having terms of less than one year.

Supply. As of December 31, 2009, Anadarko has a working interest in over 1.8 million gross acres within the Powder River Basin. Anadarko s gross acreage includes 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.

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 Wyoming Interstate Company s Medicine Bow lateral pipeline, the Colorado Interstate Gas pipeline, the Kinder Morgan interstate pipeline at the southern end of the Powder River Basin near Glenrock, Wyoming and the MGTC intrastate pipeline, a pipeline that supplies local markets in Wyoming. Anadarko owned the MGTC pipeline as of December 31, 2009.

Fort Union gathering system. The Fort Union system is a 314-mile 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 pipelines, each approximately 106 miles in length, and includes CO_2 treating facilities at the Medicine Bow plant. The system s gas treating capacity will vary depending upon the CO_2 content of the inlet gas. At current CO_2 levels, the system is capable of treating and blending over 1 Bcf/d while satisfying the CO_2 specifications of downstream pipelines.

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.

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.

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 and, as of December 31, 2009, produces gas from approximately 9,800 coal-bed methane wells in the expanding Big George coal play, the multiple seam coal fairway to the north of the Big George play and in the Wyodak coal play. Anadarko has a working interest in over 1.8 million gross acres within the Powder River Basin as of December 31, 2009. Another of the Fort Union owners has a comparable working interest in a large majority 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.

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.

Helper gathering system. 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. The Helper gathering system includes two compressor stations with a combined 14,075 horsepower and two CO_2 treating facilities.

Customers. Anadarko is the only shipper on the Helper gathering system.

Supply. The Helper Field and Cardinal Draw Fields are Anadarko-operated coal-bed methane developments on the southwestern edge of the Uintah Basin that produce from the Ferron Coals. The Helper Field covers approximately 19,000 acres as of December 31, 2009 and Cardinal Draw Field, which lies immediately to the east of Helper Field, also covers approximately 19,000 acres.

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.

Clawson gathering system. 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. The Clawson gathering system 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, 2009. The remaining throughput on the system was from one third-party producer.

Supply. Clawson Springs Field has approximately 7,000 gross acres. Production for Clawson Springs is primarily from the Cretaceous Ferron sands and coals.

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

Hilight gathering system and processing plant. The 1,157-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 the area s conventional gas production and delivers to the Hilight plant for processing. The Hilight gathering system has 10 compressor stations with 16,366 combined 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 products into propane, butanes and natural gasoline. The Hilight plant has an additional 10,755 horsepower for refrigeration and residue compression, including one compressor station.

Customers. Gas processed at the Hilight system is purchased from numerous third-party customers, with the 11 largest producers providing approximately 80% of the system throughput during 2009.

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.

Delivery Points. The Hilight gathering system delivers natural gas into MIGC s transmission line, which delivers to Glenrock, Wyoming. Hilight is not connected to an NGL pipeline, so all fractionated NGLs are sold locally through its truck and rail loading facilities.

Newcastle gathering system and processing plant. The 176-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 gross capacity of approximately 3 MMcf/d. The plant utilizes a refrigeration process and provides for fractionation of the recovered NGLs 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 includes one compressor station, with 560 horsepower. The Newcastle plant has an additional 2,100 horsepower for refrigeration and residue compression.

Customers. Gas processed at the Newcastle system is purchased from 11 third-party customers, with the largest three producers providing approximately 90% of the system throughput during 2009. The largest producer, Black Hills Exploration, provided approximately 68% of the throughput during 2009 and is a part owner of the Newcastle system.

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 production.

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.

Mid-Continent

Hugoton gathering system. The 2,034-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. The Hugoton gathering system has 43 compressor stations with a combined 102,257 horsepower of compression.

Customers. Anadarko is the largest customer on the Hugoton gathering system with 82 MMcf/d of average throughput during the year ended December 31, 2009, representing 67% of the total volume on the system. Approximately 26% of the throughput on the Hugoton system for the year ended December 31, 2009 was from one third-party shipper.

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 has an extensive acreage position with

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approximately 470,000 gross acres. By virtue of a farm out 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. Our existing asset is well-positioned to gather volumes that may be produced from new wells the third-party producer may successfully drill. In addition, Anadarko has indicated it expects an increased activity level in the area in 2010 due to recent changes in local regulations controlling the number of wells that may be drilled in a given area.

Delivery Points. The Hugoton gathering system is connected to DCP Midstream Partners, 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 NGLs 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.

West Texas

Haley gathering system. The 116-mile Haley gathering system provides gathering and dehydration services in Loving County, Texas and gathers Anadarko s production from the Delaware Basin. The Haley gathering system has historically experienced rapid growth as a result of Anadarko s successful drilling activity in the area.

Customers. Anadarko s production represented approximately 72% of the Haley gathering system s throughput for the year ended December 31, 2009. The remaining 28% of throughput is attributable to Anadarko s partner in the Haley area.

Supply. In the greater Delaware basin, Anadarko has access to approximately 410,000 gross acres as of December 31, 2009.

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.

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 its acreage surrounding our initial assets 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 Chipeta s cryogenic processing unit and Fort Union s centralized amine treating facilities provide competitive advantages to those systems.

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

Chipeta processing plant: Questar Gas Management;

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

Fort Union gathering system: Thunder Creek Gas Services;

Helper and Clawson gathering systems: Questar Gas Management;

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

Hugoton gathering system: ONEOK Gas Gathering Company, DCP Midstream Partners, LP and Pioneer Natural Resources;

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

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 the MIGC pipeline. 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. liquid and gas transportation pipelines and some gathering lines in high-population 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. We, or the entities in which we own an interest, inspect our pipelines regularly in compliance with state and federal maintenance requirements.

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 pipelines have operations and maintenance plans designed to keep the facilities in compliance with pipeline safety 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 EPA s 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, as well as the EPA s Risk Management Program, or RMP, which are designed to prevent or

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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 specified thresholds or any process which involves flammable liquid or gas in excess of 10,000 pounds. 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

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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 issued an order on rehearing on October 15, 2009. The order on rehearing generally reaffirmed the determinations in Order No. 717 and also clarified certain provisions of the Standards of Conduct.

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) 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 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

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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 $1.0 million 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 was due in July 2009 for calendar year 2008 activities. For subsequent years, the report is due annually on May 1. 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 requested modification or reconsideration of this rule. A staff technical conference was held in March 2009 to gather additional information on three issues raised in the requests for rehearing: (1) the definition of major non-interstate pipelines; (2) what constitutes scheduling for a receipt or delivery point; and (3) how a 15,000 MMBtu per day design capacity threshold would be applied. Furthermore, FERC issued an order on July 16, 2009, requesting parties to file supplemental comments on certain issues. An order on rehearing, Order No. 720-A, was issued on January 21, 2010. In that order the FERC reaffirmed its holding that it has jurisdiction over major non-interstate pipelines for the purpose of requiring public disclosure of information to enhance market transparency. Order No. 720-A also granted clarification regarding application of the rule. Major non-interstate pipelines subject to the rule have 150 days to comply with the rule s Internet posting requirements. 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. However, some of our natural gas gathering activity is subject to Internet posting requirements imposed by FERC as a result of FERC s recent market transparency initiatives. 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

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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 in some cases, 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.

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 current 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 can make no assurances, 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 in some cases, 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

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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 strict and 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, or 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 own or lease properties where hydrocarbons are being or have been handled for many years. We have generally utilized operating and disposal practices that were standard in the industry at the time, although 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.

Climate change. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, or ACES, also known as the Waxman-Markey Bill. The U.S. Senate is considering a number of comparable measures. One such measure, the Clean Energy Jobs and American Power Act, or the Boxer-Kerry Bill, has been reported out of the Senate Committee on Energy and Natural Resources, but has not yet been considered by the full Senate. Although these bills include several differences that require reconciliation before becoming law, both contain the basic feature of establishing a cap and trade system for restricting greenhouse gas emissions in the U.S. Under such system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas emission allowances corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The ultimate outcome of this legislative initiative remains uncertain. Any laws or regulations that may be adopted to restrict or reduce emissions of U.S. greenhouse gases could require us to incur increased operating costs, and could have an adverse effect on demand for the natural gas and NGLs we gather and process. In addition, at least 20 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 cap and trade programs.

Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of the natural gas we gather and process. Although we believe we would not be impacted to a greater degree than other similarly situated companies, a stringent greenhouse gas control program could have an adverse affect on our cost of doing business and could reduce demand for the natural gas and NGLs we gather and process.

In April 2007, the United States Supreme Court found that the EPA has the authority to regulate CO_2 emissions from automobiles as air pollutants under the Clean Air Act, or the CAA. Although this decision did not address CO_2 emissions from electric generating plants, the EPA has similar authority under the CAA to regulate air pollutants from those and other facilities. In April 2009, the EPA released a Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act. While the EPA s proposed findings do not specifically address stationary sources, those findings, if finalized, would be expected to support the establishment of future emission requirements by the EPA for stationary sources. In September 2009, the EPA finalized a greenhouse gas reporting rule establishing a national greenhouse gas emissions collection and reporting program. The EPA rules will require covered entities to measure greenhouse gas emissions commencing in 2010 and submit reports commencing in 2011. In September 2009, EPA also proposed new thresholds for greenhouse gas emissions that define when certain permits would be required. EPA is requesting comment on a range of values in this proposal, with the intent of selecting a single value for the greenhouse gas thresholds. These proposals, along with new federal or state restrictions on emissions of CO_2 that may be imposed in areas of the United States in which we conduct business, could also adversely affect our cost of doing business and demand for the natural gas and NGLs we gather and process.

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 dredged and fill material 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.

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 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 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 by Anadarko 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 under the direction and supervision of our general partner s board of directors. As of December 31, 2009, Anadarko employed approximately 174 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,

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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 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 statements d 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 risks 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 gathering, treating and processing volumes and pipeline throughput, including Anadarko s production, which is gathered or processed by or transported through our assets;*
- *operating results;*
- *competitive conditions;*
- *technology;*
- *the availability of capital resources to fund capital expenditures and other contractual obligations, and our ability to access those resources through the debt or equity capital markets;*
- *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;*
- *changes in the financial health of our sponsor, Anadarko;*

changes in Anadarko s capital program, strategy or desired areas of focus;

our commitments to capital projects;

the ability to utilize our existing credit arrangements, including up to $100.0 million under Anadarko s $1.3 billion credit facility, our $350.0 million revolving credit facility or our $30.0 million working capital 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 this Item 1A and the caption Critical Accounting Policies and Estimates included under Item 7 this annual report 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 currently announced 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, process and transport. A material reduction in Anadarko s production gathered, processed 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, process and transport. For the year ended December 31, 2009, Anadarko accounted for approximately 79% 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 we derive a substantial portion of our revenues from Anadarko, we are indirectly subject to risks relating to Anadarko.

Because we expect to derive a substantial majority of our revenues from Anadarko for the foreseeable future, any event, whether in our area of operations or otherwise, that adversely affects Anadarko s production, financial condition, leverage, results of operations or cash flows may adversely affect our ability to sustain or increase cash distributions to our unitholders. Accordingly, we are indirectly subject to the business risks of Anadarko, some of which are the following:

the volatility of natural gas and oil prices, which could have a negative effect on the value of its oil and natural gas properties, its drilling programs or its ability to finance its operations;

the availability of capital on an economic basis to fund its exploration and development activities;

its ability to replace reserves;

its operations in foreign countries are subject to political, economic and other uncertainties;

its drilling and operating risks, including potential environmental liabilities;

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- transportation capacity constraints and interruptions;
- adverse effects of governmental and environmental regulation; and
- losses from pending or future litigation.

Please see *Item 1A*, in Anadarko s annual report on Form 10-K for the year ended December 31, 2009 for a full discussion of the risks associated with Anadarko s business.

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.

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 announced distributions to holders of our common and subordinated units.

In order to pay the announced distribution of $0.33 per unit per quarter, or $1.32 per unit per year, we will require available cash of approximately $21.4 million per quarter, or $85.6 million per year, based on the number of general partner units and common and subordinated units outstanding at March 1, 2010. We may not have sufficient available cash from operating surplus each quarter to enable us to pay the announced 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 NGLs and 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.

Lower natural gas, NGL or oil prices could adversely affect our business.

Lower natural gas, NGL or 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, and potentially affect our vendors , suppliers and customers ability to continue operations. 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:

domestic and worldwide economic conditions;

weather conditions and seasonal trends;

the levels of domestic production and consumer demand, as affected by, among other things, concerns over inflation, geopolitical issues and the availability and cost of credit;

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.

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

Based on gross margin for the year ended December 31, 2009, approximately 13% of our processing services are provided under percent-of-proceeds and keep-whole arrangements under which the associated revenues and expenses are directly correlated with the prices of natural gas and NGLs. This percentage may significantly increase as a result of future acquisitions, if any.

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 NGL prices and other changing market conditions. We currently have in place fixed-price swap agreements with Anadarko to manage the commodity price risk otherwise inherent in our percent-of-proceeds and keep-whole contracts. To the extent that we engage in price risk management activities such as the swap agreements, we may be prevented from realizing the full benefits of price increases above the levels set by those activities. In addition, our commodity price management may expose us to the risk of financial loss in certain circumstances, including instances in which:

- the counterparties to our hedging or other price risk management contracts fail to perform under those arrangements; or

- we are unable to replace the existing hedging arrangements when they expire.

If we do not (or are unable to) effectively manage the commodity price risk associated with our commodity-exposed contracts, 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.

We may not be able to obtain funding or obtain funding on acceptable terms. 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. While our sector has rebounded from lows seen in 2008, the repricing of credit risk and the current relatively 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. Further, we may be unable to obtain adequate funding under our revolving credit facility or Anadarko s $1.3 billion credit facility if Anadarko s and/or our lending counterparties become unwilling or unable to meet their funding obligations. In addition, our access to Anadarko s $1.3 billion credit facility may be limited if Anadarko has to draw down on its entire $1.3 billion credit facility in order to meet its own capital needs or 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.

Restrictions in our revolving credit facility may limit our ability to make distributions and may limit our ability to capitalize on acquisition and other business opportunities.

The operating and financial restrictions and covenants in our revolving credit facility and any future financing agreements could restrict our ability to finance future operations or capital needs or to expand or pursue business activities associated with our subsidiaries and equity investments. Our revolving credit facility contains covenants, some of which may be modified or eliminated upon our receipt of an investment grade rating, that restrict or limit our ability to:

- make distributions if any default or event of default, as defined, occurs;

make other distributions, dividends or payments on account of the purchase, redemption, retirement, acquisition, cancellation or termination of partnership interests;

incur additional indebtedness or guarantee other indebtedness;

grant liens to secure obligations other than our obligations under our revolving credit facility or agree to restrictions on our ability to grant additional liens to secure our obligations under our revolving credit facility;

make certain loans or investments;

engage in transactions with affiliates;

make any material change to the nature of our business from the midstream energy business;

dispose of assets; or

enter into a merger, consolidate, liquidate, wind up or dissolve.

The financial covenants of our revolving credit facility include financial leverage and interest coverage ratios. The terms of the credit agreement require us to maintain a ratio of total debt to Consolidated Earnings Before Interest, Taxes, Depreciation and Amortization, or EBITDA, as defined in the credit agreement, of 4.5 or less. The terms of the credit agreement also require us to maintain a ratio of Consolidated EBITDA, as defined in the credit agreement, to interest expense of 3.0 or greater. As of December 31, 2009, we were in compliance with those covenants.

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 this 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 debt instruments may be affected by events beyond Anadarko s or 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 might have outstanding under Anadarko s 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 see the caption *Liquidity and Capital Resources* under *Item 7* of this annual report.

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, 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 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 affect any of these actions on satisfactory terms or at all.

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 rates on our floating rate debt, including amounts outstanding under our revolving credit facility and our five-year $175.0 million term loan with Anadarko (which after December 2010 will bear interest at a floating rate), 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.

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. In addition, any 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.

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 announced distribution on all of our units and the corresponding distribution on our general partner s 2.0% interest for four quarters is approximately $85.6 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 connected 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 results of operations could be adversely affected by asset impairments.

If natural gas and NGL prices continue to decrease, we may be required to write-down the value of our midstream properties if the estimated future cash flows from these properties fall below their net book value. Because we are an affiliate of Anadarko, the assets we acquire from it are recorded at Anadarko s carrying value prior to the transaction. Accordingly, we may be at an increased risk for impairments because the initial book values of substantially all of our assets do not have a direct relationship with, and in some cases could be significantly higher than, the amounts we paid to acquire such assets.

Further, at December 31, 2009, we had approximately $20.8 million of goodwill on our balance sheet. Similar to the carrying value of the assets we acquired from Anadarko, our goodwill is an allocated portion of Anadarko s goodwill, which we recorded as a component of the carrying value of the assets we acquired from Anadarko. As a result, we may be at increased risks for impairments relative to entities who acquire their assets from third parties or construct their own assets, as the carrying value of our goodwill does not reflect, and in some cases is significantly higher than, the difference between the consideration we paid for our acquisitions and the fair value of the net assets on the acquisition date.

Goodwill is not amortized, but instead must be tested at least annually for impairment, and more frequently when circumstances indicate likely impairment, by applying a fair-value-based test. Goodwill is deemed impaired to the extent that its carrying amount exceeds its implied fair value. Various factors could lead to goodwill impairments that could have a substantial negative effect on our profitability, such as if the Partnership is unable to replace the value of its depleting asset base or if other adverse events, such as lower sustained oil and gas prices, reduce the fair value of the associated reporting unit. Future non-cash asset impairments could negatively affect our results of operations.

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 margin from drip condensate sales is affected by changes in the relative prices of oil and gas.

Under our gathering agreements, we retain and sell drip 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, 2009. 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 relatively high.

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 EPAct 2005.

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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 $1.0 million 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.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could adversely impact our revenues.

An increasing percentage of our customers oil and gas production is being developed from unconventional sources, such as deep gas shales. These reservoirs require hydraulic fracturing completion processes to release the gas from the rock so it can flow through casing to the surface. Hydraulic fracturing involves the injection of water, sand and, in some cases, chemicals under pressure into the formation to stimulate gas production. Certain environmental groups have suggested that additional laws may be needed to more closely and uniformly regulate the hydraulic fracturing process, and legislation has been proposed by some members of Congress to provide for such regulation. We cannot predict whether any such legislation will ever be enacted and if so, what its provisions would be. Additional levels of regulation and permits, if required through the adoption of new laws and regulations, could lead to delays, increased operating costs and process prohibitions that could reduce the volumes of natural gas that move through our gathering systems. Such developments could materially adversely affect our revenues and results of operations.

The adoption of climate change legislation by the U.S. Congress or the issuance of new regulations by the U.S. Environmental Protection Agency with respect to climate change could increase our operating and capital costs and could have the indirect effect of decreasing demand for the products we gather, process and transport.

The American Clean Energy and Security Act of 2009, or ACES, also known as the Waxman-Markey Bill, was approved by the U.S. House of Representatives on June 26, 2009. ACES would establish a variant of a cap-and-trade plan for greenhouse gases, or GHGs, in order to address climate change and most sources of GHG emissions would be required to obtain GHG emission allowances corresponding to their historical annual emissions of GHGs. The U.S. Senate is considering comparable cap and trade legislation. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. If ACES or similar legislation is ultimately passed by the U.S. Senate and enacted into law, the net effect will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas.

The EPA has also taken recent action related to greenhouse gases, including finalizing a GHG reporting rule in September 2009 that establishes a national GHG emissions collection and reporting program. Under this reporting rule, covered entities must begin measuring GHG emissions in 2010 and submit reports commencing 2011. Based on recent developments, the EPA now has the basis to begin regulating emissions of GHGs under existing provisions of the Federal Clean Air Act. Although it may take the EPA several years to adopt and impose regulations limiting emissions of GHGs, any limitation on emissions of GHGs from our equipment and operations could require us to incur significant costs to reduce emissions of GHGs associated with our operations, along with costs for maintaining records on and reporting GHG emissions.

Although it is not possible at this time to predict the impact of future EPA regulation or whether ACES or similar climate change legislation will become law, any such laws or regulations could create incentives to conserve energy or use alternative energy sources, or could cause a sustained and significant increase in the market prices of hydrocarbon-based products, in each case potentially reducing demand for natural gas and our services. Any of these developments could have an adverse effect on our business, financial condition, results of operations or cash flows.

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. However, some of our gas gathering activities are subject to Internet posting requirements imposed by FERC as a result of FERC s recent market transparency initiatives. 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 FERC s 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 by 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 Clean Water Act and analogous state laws that regulate discharges from our facilities into state and federal waters, including wetlands;

- the federal 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, or 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 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.

We have partial ownership interests in joint venture legal entities, which affects our ability to operate and/or control these entities. In addition, we may be unable to control the amount of cash we will receive or retain from the operation of these entities and we could be required to contribute significant cash to fund our share of their operations, which could adversely affect our ability to distribute cash to our unitholders.

Our inability, or limited ability, to control the operations and/or management of joint venture legal entities in which we have a partial ownership interest may result in our receiving or retaining less than the amount of cash we expect. We also may be unable, or limited in our ability, to cause any such entity to effect significant transactions such as large expenditures or contractual commitments, the construction or acquisition of assets, or the borrowing of money.

In addition, for Fort Union, an entity in which we have a minority ownership interest, we will be unable to control ongoing operational decisions, including the incurrence of capital expenditures or additional indebtedness that we may be required to fund. Further, Fort Union may establish reserves for working capital, capital projects, environmental matters and legal proceedings, that would similarly reduce the amount of cash available for distribution. 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 occur, 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 Anadarko s business would be impacted if conditions in the energy industry were 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.

On some of our 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.

The loss of, or difficulty attracting and retaining, experienced personnel could reduce our competitiveness and prospects for future success.

The successful execution of our growth strategy and other activities integral to our operations will depend, in part, on our ability to attract and retain experienced engineering, operating, commercial and other professionals. Competition for such professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be adversely impacted.

We are required to deduct estimated future maintenance capital expenditures from operating surplus, which may result in less cash available for distribution to unitholders than if actual maintenance capital expenditures were deducted.

Our partnership agreement requires us to deduct estimated, rather than actual, maintenance capital expenditures from operating surplus. The amount of estimated maintenance capital expenditures deducted from operating surplus will be subject to review and change by our special committee at least once a year. In years when our estimated maintenance capital expenditures are higher than actual maintenance capital expenditures, the amount of cash available for distribution to unitholders will be lower than if actual maintenance capital expenditures were deducted from operating surplus. If we underestimate the appropriate level of estimated maintenance capital expenditures, we may have less cash available for distribution in future periods when actual capital expenditures begin to exceed our previous estimates. Over time, if we do not set aside sufficient cash reserves or have sufficient sources of financing available and we make sufficient expenditures to maintain our asset base, we may be unable to pay distributions at the anticipated level and could be required to reduce our distributions.

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

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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.

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.

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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* of this annual report.

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, 2010 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.

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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 662/3% of all outstanding limited partner units voting together as a single class is required to remove our general partner. As of March 1, 2010, Anadarko owns 56.3% 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

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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 March 1, 2010, Anadarko holds an aggregate of 9,254,435 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 March 1, 2010, Anadarko owns approximately 25.0% 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 56.3% 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 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.

The market price of our common units could be volatile due to a number of factors, many of which are beyond our control.

The market price of our common units could be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- changes in securities analysts   recommendations and their estimates of our financial performance;
- the public s reaction to our press releases, announcements and our filings with the SEC;
- fluctuations in broader securities market prices and volumes, particularly among securities of midstream companies and securities of publicly-traded limited partnerships;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of midstream companies;
- variations in the amount of our quarterly cash distributions;
- future issuances and sales of our common units; and
- changes in general conditions in the U.S. economy, financial markets or the midstream industry.

In recent years, the capital markets have experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. Future market fluctuations may result in a lower price of our common units.

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.

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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.

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

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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 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 clearly 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.

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, or 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 may be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons may 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.

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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.

A unitholder whose common units are loaned to a short seller to cover a short sale of common units may be considered as having disposed of those common units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose common units are loaned to a short seller to cover a short sale of common units may be considered as having disposed of the loaned common units, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

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, which would require us to file two tax returns (and could result in our unitholders receiving two K-1 Schedules) for one fiscal year, 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* of this annual report for more information.

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Item 4. ***Reserved***

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 during each quarter since our initial public offering.

	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
2009				
High Price	$ 19.73	$ 17.90	$ 15.65	$ 15.62
Low Price	$ 17.51	$ 15.39	$ 13.96	$ 12.63
Distribution per common and subordinated unit	$ 0.32	$ 0.31	$ 0.30	$ 0.30
2008				
High Price	$ 15.17	$ 16.96	$ 17.25	
Low Price	$ 10.58	$ 13.02	$ 16.15	
Distribution per common and subordinated unit	$ 0.30	$ 0.16		

As of March 1, 2010, there were approximately 15 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 1,296,570 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 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.

We completed our 2009 equity offering of 6,900,000 common units, including 900,000 common units issued pursuant to the full exercise by the underwriters of their option to purchase additional common units at a price of $18.20 per unit. Net proceeds from the offering of approximately $122.5 million were used to repay $100.0 million outstanding under our revolving credit facility and to partially fund our January 2010 Granger acquisition. The net proceeds included $2.5 million from Anadarko in exchange for 140,817 general partner units.

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	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 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.

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OTHER SECURITIES MATTERS

Sales of Unregistered Units. In connection with our 2009 equity offering, our general partner purchased an additional 140,817 general partner units to maintain its 2% general partner interest in us. In July 2009, we acquired the Chipeta assets from Anadarko for consideration consisting of $101.5 million cash, 351,424 of our common units and 7,172 of our general partner units. Further, in December 2008, we acquired the Powder River 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 these transactions were issued to our general partner or other subsidiaries of Anadarko in private placements that were 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 and certain employees under the LTIP. Please read the information under *Item 12* of this annual report, which is incorporated by reference into this *Item 5*.

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. In May 2008, we closed our initial public offering. Concurrent with the closing of the offering, Anadarko contributed to us the assets and liabilities of AGC, PGT and MIGC, which we refer to as our initial assets. In December 2008, we closed the Powder River acquisition with Anadarko and in July 2009, we closed the Chipeta acquisition with Anadarko. Anadarko acquired MIGC and the Powder River assets in connection with its August 23, 2006 acquisition of Western and Anadarko acquired the Chipeta assets in connection with its August 10, 2006 acquisition of Kerr-McGee.

Our acquisition of the initial assets, the Powder River acquisition and the Chipeta 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 Western Gas Partners, LP and its subsidiaries thereafter, combined with the financial results and operations of MIGC and the Powder River assets, from August 23, 2006 thereafter, and combined with the financial results and operations of the Chipeta assets, from August 10, 2006 thereafter.

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The information in the following table should be read together with *Item 7* of this annual report.

	Summary Financial Information				
	2009	**2008(1)**	**2007(1)**	**2006(1)**	**2005**
	(In thousands, except per unit data, throughput and gross margin per Mcf)				
Statement of Income Data (for the year ended):					
Total revenues	**$ 245,119**	$ 344,506	$ 261,493	$ 128,610	$ 71,650
Costs and expenses	**124,424**	212,943	166,994	80,752	35,720
Depreciation, amortization and impairment	**40,065**	45,396	30,785	20,230	15,447
Total operating expenses	**164,489**	258,339	197,779	100,982	51,167
Operating income	**80,630**	86,167	63,714	27,628	20,483
Interest income (expense), net	**6,945**	9,191	(7,805)	(9,574)	(8,650)
Other income (expense), net	**42**	196	(15)	(26)	66
Income tax expense(2)	**12**	13,988	19,424	5,327	4,789
Net income	87,605	81,566	36,470	12,701	7,110
Net income (loss) attributable to noncontrolling interests	**10,260**	7,908	(92)		
Net income attributable to Western Gas Partners, LP	**$ 77,345**	$ 73,658	$ 36,562	$ 12,701	$ 7,110
Key Performance Measures (for the year ended):					
Gross margin(3)	**$ 193,983**	$ 204,496	$ 149,211	$ 86,804	$ 65,643
Adjusted EBITDA(4)	**111,160**	124,457	91,831	47,239	35,930
Distributable cash flow(4)	**102,176**	117,277	n/a	n/a	n/a
General partner s interest in net income(5)	**1,428**	842	n/a	n/a	n/a
Common unitholders interest in net income(5)	**37,035**	20,841	n/a	n/a	n/a
Subordinated unitholders interest in net income(5)	**32,945**	20,420	n/a	n/a	n/a
Net income per common unit (basic and diluted)	**$ 1.25**	$ 0.78	n/a	n/a	n/a
Net income per subordinated unit (basic and diluted)	**$ 1.24**	$ 0.77	n/a	n/a	n/a
Distributions per unit	**$ 1.23**	$ 0.46	n/a	n/a	n/a
Balance Sheet Data (at period end):					
Property, plant and equipment, net	**$ 700,496**	$ 686,353	$ 607,971	$ 478,873	$ 200,451
Total assets	**1,084,229**	1,033,155	646,914	518,337	206,373
Total long-term liabilities	**187,667**	186,095	139,684	140,071	37,664
Total partners capital and equity	**$ 878,449**	$ 804,625	$ 494,537	$ 366,532	$ 160,585

Cash Flow Data (for the year ended):					
Net cash provided by (used in):					
Operating activities	**$ 113,958**	$ 145,430	$ 73,223	$ 33,304	$ 30,131
Investing activities	**(164,007)**	(542,586)	(143,274)	(42,963)	(21,076)
Financing activities	**83,959**	433,230	69,593	10,113	(9,067)
Capital expenditures	**$ 62,174**	$ 99,491	$ 136,874	$ 42,963	$ 20,841
Operating Data (volumes in MMcf/d):					
Gathering and transportation throughput	**883**	967	987	971	798
Processing throughput(6)	**396**	283	31	30	
Equity investment throughput(7)	**120**	112	84		
Total throughput	**1,399**	1,362	1,102	1,001	798
Throughput attributable to noncontrolling interests	**180**	124			
Throughput attributable to Western Gas Partners, LP	**1,219**	1,238	1,102	1,001	798
Average gross margin per Mcf(8)	**$ 0.38**	$ 0.41	$ 0.37	$ 0.23	$ 0.22
Average gross margin per Mcf attributable to Western Gas Partners, LP	**$ 0.40**	$ 0.42	$ 0.37	$ 0.23	$ 0.22

(1) Financial information for 2008, 2007 and 2006 has been revised to include results attributable to the Chipeta acquisition. See *Note 1 Description of Business and Basis of Presentation Chipeta Acquisition* of the notes to the consolidated financial statements in under *Item 8* of this annual report.

(2) Income earned by the Partnership, a non-taxable entity for U.S. federal income tax purposes, including and subsequent to May 14, 2008, with respect to the initial assets, and including and subsequent to December 19, 2008, with respect to the Powder River assets, was subject only to Texas margin tax while

income earned prior to May 14, 2008, with respect to the initial assets, and prior to December 19, 2008, with respect to the Powder River assets, was subject to federal and state income tax. Income attributable to the Chipeta assets was subject to federal and state income tax for periods prior to June 1, 2008, at which time substantially all of the Chipeta assets were contributed to a non-taxable entity for U.S. federal income tax purposes. See *Note 6 Transactions with Affiliates* of the notes to the consolidated financial statements in under *Item 8* of this annual report.

(3) We define gross margin as total revenues less cost of product.

(4) Adjusted EBITDA and distributable cash flow are not defined in GAAP. For descriptions and reconciliations of Adjusted EBITDA and distributable cash flow to their most directly comparable financial measures calculated and presented in accordance with GAAP, please see the caption *How We Evaluate Our Operations* under *Item 7* of this annual report. We did not utilize a distributable cash flow measure prior to becoming a publicly traded partnership in 2008 and, as such, did not differentiate between maintenance and capital expenditures prior to 2008.

(5) The Partnership s net income attributable to the Partnership Assets for periods including and subsequent to the Partnership s acquisitions of the Partnership Assets is allocated to the general partner and the limited partners, including any subordinated unitholders, in accordance with their respective ownership percentages. Prior to our acquisition of the Partnership Assets, all income is attributed to the Parent. See *Note 5 Net Income per Limited Partner Unit* of the notes to the consolidated financial statements under *Item 8* of this annual report.

(6) Processing throughput consists of 100% of Chipeta and Hilight plant volumes and 50% of Newcastle plant volumes.

(7) Equity investment throughput represents the Partnership s 14.81% share of Fort Union s gross volumes.

(8) Calculated as gross margin (total revenues less cost of product), divided by total throughput, including 100% of gross margin and volumes attributable to Chipeta and 14.81% interest in income and volumes attributable to Fort Union.

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 2009. Significant operational and financial highlights include:

In July 2009, we acquired a 51% membership interest in Chipeta Processing LLC, or Chipeta, together with related midstream assets from Anadarko.

In October 2009, we entered into a three-year senior unsecured revolving credit facility with aggregate initial commitments of $350.0 million. This revolving credit facility matures in October 2012 and bears interest at a variable rate.

In December 2009, we issued 6,900,000 common units at a price of $18.20 per unit to the public. Net proceeds from the offering of approximately $122.5 million were used to repay $100.0 million outstanding under our revolving credit facility and to partially fund the January 2010 Granger acquisition.

Our stable operating cash flow along with our Chipeta acquisition, combined with a focus on cost reduction and capital spending discipline, enabled us to raise our distribution over three consecutive quarters to $0.33 per unit for the fourth quarter of 2009, representing a 10.0% increase over the distribution for the fourth quarter of 2008.

Although the current commodity price environment, particularly for natural gas, has resulted in lower drilling activity throughout the areas in which we operate, throughput decreases were substantially offset by throughput increases at the Chipeta plant and Fort Union system due to facility expansions. The throughput attributable to Western Gas Partners, LP, for the year ended December 31, 2009, totaled approximately 1,219 MMcf/d, representing an approximate 2% decrease compared to the year ended December 31, 2008.

ACQUISITIONS

Concurrent with the closing of the initial public offering in May 2008, Anadarko contributed the assets and liabilities of AGC, PGT and MIGC to us 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 us for consideration consisting of $175.0 million in cash, which was funded by a note from Anadarko, 2,556,891 common units and 52,181 general partner units. In connection with the Chipeta acquisition in July 2009, Anadarko contributed the Chipeta assets to us for consideration consisting of $101.5 million in cash, which was funded by a note from Anadarko, 351,424 common units and 7,172 general partner units. In November 2009, Chipeta closed its $9.1 million acquisition from a third party of the Natural Buttes plant. In connection with the Granger acquisition in January 2010, Anadarko contributed the Granger assets to us for consideration consisting of $241.7 million in cash, which was funded with $210.0 million of borrowings under our revolving credit facility and $31.7 million of cash on hand, as well as the issuance of 620,689 common units to Anadarko and 12,677 general partner units to our general partner. See the caption *Acquisitions* under *Items 1 and 2* of this annual report for additional transaction and asset descriptions.

Because Anadarko owns the Partnership s general partner, each acquisition of Partnership Assets, except the Natural Buttes plant, was considered a transfer of net assets between entities under common control. As a result, after each acquisition of assets from Anadarko, we are required to revise our financial statements to include the activities of the those assets as of the date of common control. Our historical financial statements for the years ended December 31, 2008 and 2007 as presented in our annual report on Form 10-K for the year ended December 31, 2008, which included the results attributable to the Powder River assets, have been recast to reflect the results attributable to the Chipeta assets as if the Partnership owned a 51% interest in Chipeta and associated midstream assets for all periods presented. The following tables present the impact to the consolidated statements of income attributable to the Chipeta assets (in thousands):

	Partnership Historical	Chipeta Acquisition	Combined
	Year Ended December 31, 2008		
Revenues	$ 311,648	$ 32,858	$ 344,506
Operating expenses	241,931	16,408	258,339
Operating income	69,717	16,450	86,167
Interest and other income, net	9,336	51	9,387
Income before income taxes	79,053	16,501	95,554
Income tax expense	13,777	211	13,988

Net income	65,276	16,290	81,566
Net income attributable to noncontrolling interests		7,908	7,908
Net income attributable to Western Gas Partners, LP	$ 65,276	$ 8,382	$ 73,658

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	Partnership Historical	Chipeta Acquisition	Combined
	Year Ended December 31, 2007		
Revenues	$ 261,493	$	$ 261,493
Operating expenses	197,475	304	197,779
Operating income	64,018	(304)	63,714
Interest and other (expense), net	(7,820)		(7,820)
Income (loss) before income taxes	56,198	(304)	55,894
Income tax expense (benefit)	19,540	(116)	19,424
Net income	36,658	(188)	36,470
Net income (loss) attributable to noncontrolling interests		(92)	(92)
Net income attributable to Western Gas Partners, LP	$ 36,658	$ (96)	$ 36,562

OUR OPERATIONS

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 and Item 1A of this annual report. For ease of reference, we refer to the historical financial results of the Partnership Assets prior to our acquisitions as being our historical financial results. Unless the context otherwise requires, references to we, us, our the Partnership or Western Gas Partners are intended to refer to the business and operations of AGC and PGT 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 business and operations of MIGC and the Powder River assets since August 23, 2006 and combined with the business and operations of the Chipeta assets since August 10, 2006. Anadarko refers to Anadarko Petroleum Corporation and its consolidated subsidiaries, excluding the Partnership and Parent refers to Anadarko prior to our acquisition of assets from Anadarko. Affiliates refers to wholly owned and partially owned subsidiaries of Anadarko, excluding the Partnership.

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, 2009, approximately 87% of our total revenues and 79% 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 and solely with respect to the gathering systems connected to our initial assets, we received a significant dedication from our largest customer, Anadarko. Specifically, Anadarko has dedicated to us all of the natural gas production it owns or controls from (i) wells that are currently connected to such gathering systems, and (ii) additional wells that are drilled within one mile of wells connected to such gathering systems, as those 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 these gathering systems.

Based on gross margin for the year ended December 31, 2009, approximately 80% 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, process, 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 gross margin for the year ended December 31, 2009, approximately 13% of our services are provided pursuant to percent-of-proceeds and keep-whole contracts pursuant to which we have commodity price exposure. We have fixed-price swap agreements with Anadarko to manage the commodity price risk inherent in substantially all of our percent-of-proceeds and keep-whole contracts. See *Note 6 Transactions with Affiliates* of the notes to the consolidated financial statements included under *Item 8* of this annual report.

For the year ended December 31, 2009, approximately 3% of our gross margin is attributable to drip condensate and approximately 4% of our gross margin is attributable to equity income from our interest in Fort Union, changes in our imbalance positions and other revenue.

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 settlement of natural gas imbalances. Please read *Item 7A* of this annual report.

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, the Powder River acquisition and the Chipeta acquisition, the results of operations, financial condition and cash flows vary significantly for 2009 and 2008 as compared to periods ending prior to our initial public offering. Please see the caption *Items Affecting the Comparability of Our Financial Results*, set forth below in this *Item 7*.

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, (2) gross margin, (3) operating and maintenance expenses, (4) general and administrative expenses, (5) Adjusted EBITDA and (6) distributable cash flow.

Throughput. Throughput is the most important operational variable in assessing our ability to generate revenues. In order to maintain or increase throughput 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 that are dedicated to our systems, recompletions of existing wells connected 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. During the year ended December 31, 2009, we added 52 receipt points to our systems with average initial throughput of approximately 4.0 MMcf/d per receipt point.

To maintain and increase throughput 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 identify new opportunities and to attempt to maintain a full subscription of MIGC s firm capacity.

Gross margin. We define gross margin as total revenues less cost of product. We consider gross margin to provide information useful in assessing our results of operations and our ability to internally fund capital expenditures and to service or incur additional debt. Cost of product expenses include (i) costs associated with the purchase of natural gas and NGLs pursuant to our percent-of-proceeds and keep-whole processing

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contracts, (ii) costs associated with the valuation of our gas imbalances, (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 pursuant to our contracts. These expenses are subject to variability, although our exposure to commodity price risk attributable to our percent-of-proceeds and keep-whole contracts is mitigated through our commodity price swap agreements with Anadarko.

Operating and maintenance expenses. We monitor operating and maintenance expenses to assess the impact of such costs on the profitability of our assets and to evaluate the overall efficiency of our operations. Operation and maintenance expenses include, among other things, field 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 our acquisition of the Partnership Assets, certain of these expenses are incurred under and governed by our services and secondment agreement with Anadarko.

General and administrative expenses. To help ensure the appropriateness of our general and administrative expenses and maximize our cash available for distribution, we monitor such expenses through comparison to prior periods, the annual budget approved by our general partner s board of directors, as well as to general and administrative expenses incurred by similar midstream companies. General and administrative expenses for periods prior to our acquisition of the Partnership Assets include reimbursements attributable to costs incurred by Anadarko on our behalf and allocations of general and administrative costs by Anadarko to us. For these periods, Anadarko received compensation or reimbursement through a management services fee. For periods subsequent to our acquisition of the Partnership 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 expenses, investor relations expenses, director fees, 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 certain allocated general and administrative expenses was capped at $6.9 million for the year ended December 31, 2009. In connection with the January 2010 Granger acquisition, the cap under the omnibus agreement was increased to $8.3 million for the year ended December 31, 2010, subject to adjustment to reflect expansions of our operations through the acquisition or construction of new assets or businesses and with the concurrence of the special committee of our general partner s board of directors. If the Omnibus Agreement is not further amended by the parties, our general partner will determine the general and administrative expenses to be reimbursed by us in accordance with our partnership agreement for periods subsequent to December 31, 2010. 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. Public company expenses not subject to the cap contained in the omnibus agreement, excluding equity-based compensation, were $7.5 million and $4.5 million for the years ended December 31, 2009 and 2008, respectively.

Adjusted EBITDA. We define Adjusted EBITDA as net income (loss) attributable to Western Gas Partners, LP, plus distributions from equity investee, non-cash equity-based compensation expense, expenses in excess of the omnibus cap, interest expense, income tax expense, depreciation and amortization, 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, commercial banks and rating agencies, use to assess, among other measures:

- 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.

Distributable cash flow. We define distributable cash flow as Adjusted EBITDA, plus interest income, less net cash paid for interest expense, maintenance capital expenditures, and income taxes. We use distributable cash flow to compare distributable cash flow to the cash distributions we expect to pay our unitholders. Using this measure, management can quickly compute the coverage ratio of estimated cash flows to planned cash distributions. We believe this measure is useful to investors because this measurement is used by many companies, analysts and others in the industry as a performance measurement tool to evaluate our operating and financial performance and compare it with the performance of other publicly traded partnerships.

We did not utilize a distributable cash flow measure prior to becoming a publicly traded partnership in 2008 and, as such, did not differentiate between maintenance and capital expenditures prior to 2008 and do not report distributable cash flow for periods prior to 2008.

Distributable cash flow should not be considered an alternative to net income, earnings per unit, operating income, cash flow from operating activities or any other measure of financial performance presented in accordance with GAAP. Distributable cash flow excludes some, but not all, items that affect net income and operating income and this measure may vary among other companies. Therefore, distributable cash flow as presented may not be comparable to a similarly titled measure of other companies. Furthermore, while distributable cash flow is a measure we use to assess our ability to make distributions to our unitholders, it should not be viewed as indicative of the actual amount of cash that we have available for distributions or that we plan to distribute for a given period.

Reconciliation to GAAP measures. Adjusted EBITDA and distributable cash flow are not defined in GAAP. The GAAP measures most directly comparable to Adjusted EBITDA are net income attributable to Western Gas Partners, LP and net cash provided by operating activities and the GAAP measure most directly comparable to distributable cash flow is net income. Our non-GAAP financial measures of Adjusted EBITDA and distributable cash flow should not be considered as alternatives 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 or distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA and distributable cash flow may be defined differently by other companies in our industry, our definitions of Adjusted EBITDA and distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

Management compensates for the limitations of Adjusted EBITDA and distributable cash flow as analytical tools by reviewing the comparable GAAP measures, understanding the differences between Adjusted EBITDA and distributable cash flow compared to (as applicable) 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 attributable to Western Gas Partners, LP and net cash provided by operating activities and a reconciliation of the non-GAAP financial measure of distributable cash flow to the GAAP financial measure of net income:

	Year Ended December 31,		
	2009	2008(1)	2007(1)
		(In thousands)	
Reconciliation of Adjusted EBITDA to net income attributable to Western Gas Partners, LP			
Adjusted EBITDA	$ 111,160	$ 124,457	$ 91,831
Less:			
Distributions from equity investee	5,487	5,128	1,349
Non-cash equity-based compensation expense	3,580	1,924	
Expenses in excess of omnibus cap	842		
Interest expense, net	9,955	1,512	7,805
Income tax expense(2)	12	13,931	19,481
Depreciation and amortization(2)	37,858	34,568	30,636
Impairment		9,354	
Other expense, net			15
Add:			
Equity income, net	6,982	4,736	4,017
Interest income from note affiliate	16,900	10,703	
Other income, net(2)	37	179	
Net income attributable to Western Gas Partners, LP	$ 77,345	$ 73,658	$ 36,562
Reconciliation of Adjusted EBITDA to net cash provided by operating activities			
Adjusted EBITDA	$ 111,160	$ 124,457	$ 91,831
Adjusted EBITDA attributable to noncontrolling interests	12,462	9,422	
Interest income (expense), net	6,945	9,191	(7,805)
Expenses in excess of omnibus cap	(842)		
Non-cash equity-based compensation expense	(3,580)	(1,924)	
Current income tax expense	(266)	(12,154)	(8,724)
Other income (expense), net	42	196	(15)
Distributions from equity investee less than (in excess of) equity income, net	1,495	(392)	2,668
Changes in operating working capital:			
Accounts receivable and natural gas imbalances	(688)	(3,736)	(3,692)
Accounts payable and accrued expenses	(12,713)	19,950	458
Other, including changes in non-current assets and liabilities	(57)	420	(1,498)
Net cash provided by operating activities	$ 113,958	$ 145,430	$ 73,223

(1) Financial information for 2008 and 2007 has been revised to include results attributable to the Chipeta assets.

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(2) Includes the Partnership s 51% share of depreciation and amortization, other income, net and income tax expense attributable to the Chipeta assets.

	Year Ended December 31, 2009	2008(1)
	(In thousands)	
Reconciliation of distributable cash flow to net income attributable to Western Gas Partners, LP		
Distributable cash flow	$ 102,176	$ 117,277
Less:		
Distributions from equity investee	5,487	5,128
Non-cash share-based compensation expense	3,580	1,924
Expenses in excess of omnibus cap	842	
Interest expense, net (non-cash settled)		1,148
Income tax expense(2)	12	13,931
Depreciation and amortization(2)	37,858	34,568
Impairments		9,354
Add:		
Equity income, net	6,982	4,736
Cash paid for maintenance capital expenditures	15,929	17,519
Other income, net(2)	37	179
Net income attributable to Western Gas Partners, LP	$ 77,345	$ 73,658

(1) Financial information for 2008 has been revised to include results attributable to the Chipeta assets. See *Note 1 Description of Business and Basis of Presentation Chipeta Acquisition* of the notes to the consolidated financial statements under *Item 8* of this annual report.

(2) Depreciation and amortization expense, other income, net and income tax expense for purposes of reconciling Adjusted EBITDA and distributable cash flow to net income includes 51% of the respective amounts attributable to Chipeta Processing LLC.

ITEMS AFFECTING THE COMPARABILITY OF OUR FINANCIAL RESULTS

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

General and Administrative Expenses under the Omnibus Agreement. 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. Prior to our ownership of the Partnership Assets, our historical consolidated financial statements reflect a management services fee representing the general and administrative expenses attributable to the Partnership Assets. During the years ended December 31, 2009 and 2008, Anadarko billed us $6.9 million and $3.4 million, respectively, in allocated general and administrative expenses subject to the cap contained in the omnibus agreement. This amount is greater than amounts allocated to us by Anadarko for the aggregate management services fees reflected in our historical consolidated financial statements for periods prior to our ownership of the Partnership Assets and will increase in future periods as we acquire additional assets. In addition, our general and administrative expenses for the year ended December 31, 2009, included $0.8 million of expenses incurred by Anadarko in excess of the cap contained in the omnibus agreement. Such expenses were recorded as a capital contribution from Anadarko and did not impact the Partnership s cash flows. We also incurred $7.5 million and $4.5 million in public company expenses, excluding equity-based

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compensation, during the years ended December 31, 2009 and 2008, respectively. We did not incur public company expenses prior to our initial public offering in May 2008.

Interest expense on intercompany balances. For periods prior to May 14, 2008, with respect to our initial assets, prior to December 19, 2008, with respect to the Powder River assets, and prior to June 1, 2008 (the date on which Anadarko initially contributed assets to Chipeta), with respect to Chipeta, we incurred interest expense or earned interest income on current intercompany balances with Anadarko. These intercompany balances were extinguished through non-cash transactions in connection with the closing of our initial public offering, the Powder River acquisition and Anadarko s initial contribution of assets to Chipeta; 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, prior to and including June 1, 2008, with respect to Chipeta, and prior to and including December 19, 2008, with respect to the Powder River assets.

Note receivable from Anadarko. 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%. For periods including and subsequent to May 14, 2008, interest income attributable to the note is reflected in our consolidated financial statements so long as the note remains outstanding.

Term loan agreements and revolving credit agreement. In connection with the Powder River acquisition in December 2008, we entered into a five-year, $175.0 million term loan agreement with Anadarko, under which we pay interest at a fixed rate of 4.00% for the first two years and a floating rate of interest at three-month LIBOR plus 150 basis points for the final three years. In connection with the Chipeta acquisition in July 2009, we entered into a three-year, 7.00% fixed rate, $101.5 million term loan agreement with Anadarko. In October 2009, we borrowed $100.0 million under our new revolving credit facility and used $2.0 million of cash on hand to refinance the $101.5 million three-year term loan with Anadarko and related accrued interest. In December 2009, we issued 6.9 million common units in connection with our 2009 equity offering and repaid the $100.0 million outstanding under our revolving credit facility. In January 2010, we borrowed $210.0 million under the revolving credit facility to partially fund the Granger acquisition. Interest expense on our notes and credit facilities will be incurred so long as debt remains outstanding.

Cash management. We expect to rely upon external financing sources, including commercial bank borrowings and long-term debt and equity issuances, to fund our acquisitions and expansion capital expenditures. Historically, we largely relied on internally generated cash flows and capital contributions from Anadarko to satisfy our capital expenditure requirements. 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 and were funded by Anadarko s working capital. Effective on May 14, 2008, with respect to our initial assets, and effective on December 19, 2008, with respect to the Powder River assets, all affiliate and third-party transactions are funded by our working capital. Prior to June 1, 2008 with respect to Chipeta, 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 Chipeta through an adjustment to parent net investment. Subsequent to June 1, 2008, Chipeta cash-settled transactions directly with third parties and with Anadarko affiliates. This impacts the comparability of our cash flow statements, working capital analysis and liquidity.

Commodity price swap agreements. Our financial results for historical periods reflect commodity price changes, which, in turn, impact the financial results derived from our percent-of-proceeds and keep-whole processing contracts. Effective January 1, 2009, substantially all commodity price risk associated with our percent-of-proceeds and keep-whole processing contracts has been mitigated through our fixed-price commodity price swap agreements with Anadarko that extend through December 31, 2011, with an option to extend through 2013. See *Note 6 Transactions with Affiliates* of the notes to the consolidated financial statements included under *Item 8* in this annual report.

Federal income taxes. We are generally not subject to federal or state income tax other than Texas margin tax. Federal and state income tax expense was recorded for periods ending prior to May 14, 2008, with respect to income generated by our initial assets, prior to June 1, 2008, with respect to income generated by the Chipeta assets, and prior to December 19, 2008, with respect to income generated by the Powder River assets. For periods including and subsequent to May 14, 2008, with respect to income generated by our initial assets, including and subsequent to June 1, 2008, with respect to income generated by the Chipeta assets, and including and subsequent to December 19, 2008, with respect to income generated by the Powder River assets, we are no longer subject to federal income tax and 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.

Distributions. We made cash distributions to our unitholders and our general partner following our initial public offering in May 2008. During the years ended December 31, 2009 and 2008, the Partnership paid cash distributions to its unitholders of approximately $70.1 million and $24.8 million, respectively. On January 21, 2010, the board of directors of the Partnership s general partner declared a cash distribution to the Partnership s unitholders of $0.33 per unit for the three months ended December 31, 2009, which equates to approximately $21.4 million per full quarter, or approximately $85.6 million per full year, based on the number of common, subordinated and general partner units outstanding as of March 1, 2010.

Equity-based compensation plans. 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 under the LTIP and incentive unit grants have been made under the Incentive Plan. These grants 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. For periods including and subsequent to May 14, 2008, the Partnership s general and administrative expenses include equity-based compensation costs allocated by Anadarko to the Partnership for grants made under the LTIP and Incentive Plan as well as under 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). Equity-based compensation expense attributable to grants made under the LTIP will impact our cash flows from operating activities only to the extent cash payments are made to a participant in lieu of the actual issuance of common units to 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 who provided services to us pursuant to the omnibus agreement 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 in that agreement for the periods to which such expense limit applies. Equity-based compensation granted under the Anadarko Incentive Plans does not impact our cash flow from operating activities. 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 under *Item 8* of this annual report.

Gas gathering agreements. 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 with respect to the initial assets. 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 with respect to the initial assets. Pursuant to the terms of the new agreements, our fees for gathering and treating services rendered to Anadarko increased. This

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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 with respect to the initial assets 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.

Granger acquisition. In January 2010, we acquired the following assets from Anadarko: (i) the Granger gathering system with related compressors and other facilities, and (ii) the Granger complex, consisting of two cryogenic trains, two refrigeration trains, an NGLs fractionation facility, and ancillary equipment. Beginning with our quarterly report for the first quarter of 2010, we will recast our historic financial statements to include the Granger assets from August 2006, when Anadarko acquired the assets in connection with its acquisition of Western. The acquisition will impact the comparability of our historic financial statements presented herein to our future financial statements. See *Note 13 Subsequent Events Granger acquisition* of the notes to the consolidated financial statements under *Item 8* of this annual report.

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.

Impact of natural gas prices. The recent natural gas price environment has resulted in lower drilling activity, resulting in fewer new well connections and, in some cases, temporary curtailments of production throughout areas in which we operate. A continued low gas price environment may result in further reductions in drilling activity or temporary curtailments of production. 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 capital invested by Anadarko and third parties in the exploration for and development of new natural gas reserves. To the extent opportunities are available, we will continue to connect new wells to our systems to mitigate the impact of natural production declines in order to maintain throughput on our systems. However, our success in connecting new wells to our systems is dependent on activities of natural gas producers and shippers.

Access to 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 and acquisitions. Recent market turbulence has from time to time 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

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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.

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 an increase in the competition for and cost of personnel and equipment. As a result of the recent decline in commodity prices, we have and will continue to actively work with our suppliers to negotiate cost savings on services and equipment to more accurately reflect the current industry environment. To the extent we are unable to negotiate lower costs, or recover higher costs through escalation provisions provided for in our contracts, our operating results will be adversely impacted.

Acquisition opportunities. As of December 31, 2009, Anadarko s total domestic midstream asset portfolio, excluding assets we own, consisted of 13 gathering systems with an aggregate throughput of approximately 2.1 Bcf/d, and 12 processing and/or treating facilities. A key component of our growth strategy is to acquire midstream assets from Anadarko and third parties over time. In December 2008, we acquired the Powder River assets from Anadarko, in July 2009, we acquired the Chipeta assets from Anadarko and in January 2010, we acquired the Granger assets from Anadarko. As of December 31, 2009, Anadarko owns a 2.0% general partner interest in us, all of our IDRs and a 54.8% 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 certain 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.

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, 2009, 2008 and 2007:

	Year Ended December 31, 2009	2008(1) (In thousands)	2007(1)
Revenues			
Gathering, processing and transportation of natural gas	$ 151,816	$ 138,864	$ 104,026
Natural gas, natural gas liquids and condensate sales	83,751	188,426	148,923
Equity income and other, net	9,552	17,216	8,544
Total revenues	245,119	344,506	261,493
Operating expenses(2)			
Cost of product	51,136	140,010	112,282
Operation and maintenance	45,901	50,828	40,756
General and administrative	20,136	15,345	8,365
Property and other taxes	7,251	6,760	5,591
Depreciation and amortization	40,065	36,042	30,785
Impairment		9,354	
Total operating expenses	164,489	258,339	197,779
Operating income	80,630	86,167	63,714
Interest income (expense), net	6,945	9,191	(7,805)
Other income (expense), net	42	196	(15)
Income before income taxes	87,617	95,554	55,894
Income tax expense	12	13,988	19,424
Net income	87,605	81,566	36,470
Net income (loss) attributable to noncontrolling interests	10,260	7,908	(92)
Net income attributable to Western Gas Partners, LP	$ 77,345	$ 73,658	$ 36,562
Gross margin(3)	$ 193,983	$ 204,496	$ 149,211
Adjusted EBITDA(3)	111,160	124,457	91,831
Distributable cash flow(3)	102,176	117,277	n/a

(1) Financial information for 2008 and 2007 has been revised to include results attributable to the Chipeta assets. See *Note 1   Description of Business and Basis of Presentation   Chipeta Acquisition* of the notes to the consolidated

financial statements under *Item 8* of this annual report..

(2) Operating expenses include amounts charged by affiliates to us for services as well as reimbursement of amounts paid by affiliates to third parties on our behalf. *See Note 6 Transactions with Affiliates* of the notes to the consolidated financial statements under *Item 8* of this annual report.

(3) Gross margin, Adjusted EBITDA and distributable cash flow are defined above under the caption *How we Evaluate Our Results* within this *Item 7.* Such caption also includes reconciliations of Adjusted EBITDA and distributable cash flow to their 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, 2009 refer to the comparison of the year ended December 31, 2009 to the year ended December 31, 2008.

Similarly, 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.

Executive Summary

Total revenues decreased by $99.4 million for the year ended December 31, 2009 and increased $83.0 million for the year ended December 31, 2008. Gathering, processing and transportation revenues increased $13.0 million; natural gas, NGL and condensate revenues decreased $104.7 million and equity income and other revenues decreased $7.7 million for the year ended December 31, 2009. Gathering, processing and transportation revenues increased $34.8 million; natural gas, NGL and condensate revenues increased $39.5 million and equity income and other revenues increased $8.7 million for the year ended December 31, 2008.

Net income attributable to Western Gas Partners, LP increased by $3.7 million for the year ended December 31, 2009, consisting of a $93.9 million decrease in total operating expenses primarily due to an $88.9 million decrease in cost of product from lower prices and a $14.0 million decrease in income tax expense, substantially offset by a $99.4 million decrease in revenues, a $2.2 million decrease in interest income, net due to an increase in interest expense from additional borrowings and a $2.4 million increase in net income attributable to noncontrolling interests due to increased Chipeta income.

Net income attributable to Western Gas Partners, LP increased by $37.1 million for the year ended December 31, 2008 consisting of an $83.0 million increase in total revenues driven by gathering rate increases, increased processing volumes, increased condensate sales, an increase in other revenues from changes in gas imbalance positions and gas prices, a $17.0 million increase in interest income, net and a $5.4 million decrease in income tax expense. These items are partially offset by a $27.7 million increase in cost of product primarily from higher prices, an $8.0 million increase in net income attributable to noncontrolling interests due to increased Chipeta income and a $32.8 million increase in other operating expenses for the year ended December 31, 2008.

Operating Statistics

	2009	2008	Δ(1)	2007	Δ(1)
	(MMcf/d, except percentages and gross margin per Mcf)				
Gathering and transportation throughput					
Affiliates	761	832	(9)%	910	(9)%
Third parties	122	135	(10)%	77	75%
Total gathering and transportation throughput	883	967	(9)%	987	(2)%
Processing throughput(2)					
Affiliates	338	234	44%		nm(4)
Third parties	58	49	18%	31	58%
Total processing throughput	396	283	40%	31	813%
Equity investment throughput(3)	120	112	7%	84	33%
Total throughput	1,399	1,362	3%	1,102	24%
Throughput attributable to noncontrolling interest owners	180	124	45%		nm(4)

Total throughput attributable to Western Gas Partners, LP		1,219		1,238	(2)%		1,102	12%
Gross margin per Mcf								
Gross margin per Mcf	$	0.38	$	0.41	(7)%	$	0.37	11%
Gross margin per Mcf attributable to Western Gas Partners, LP	$	0.40	$	0.42	(5)%	$	0.37	14%

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(1) Represents the percentage change for the year ended December 31, 2009 or for the year ended December 31, 2008.

(2) Consists of 100% of Chipeta and Hilight plant volumes and 50% of Newcastle system volumes.

(3) Represents our 14.81% share of Fort Union s gross volumes.

(4) Percent change is not meaningful.

Total throughput, which consists of affiliate, third-party and equity investment volumes, increased by 37 MMcf/d and 260 MMcf/d for the year ended December 31, 2009 and for the year ended December 31, 2008, respectively. Total throughput attributable to Western Gas Partners, LP, which excludes the noncontrolling interest owner s proportionate share of Chipeta s throughput, decreased by 19 MMcf/d for the year ended December 31, 2009 and increased by 136 MMcf/d for the year ended December 31, 2008.

Affiliate gathering and transportation throughput decreased by 71 MMcf/d and 78 MMcf/d for the year ended December 31, 2009 and for the year ended December 31, 2008, respectively. The decrease for both the year ended December 31, 2009 and 2008 is primarily comprised of throughput decreases at the Pinnacle, Dew, Haley and Hugoton systems due to natural production declines and changes in contract terms, partially offset by affiliate throughput increases at the MIGC system.

Contract terms for one Pinnacle customer changed in August 2008 when a producer chose to take its product in-kind and contract directly with us for gathering services, rather than to sell its production to our affiliate at the wellhead, resulting in a shift in volumes from affiliate to third-party. Affiliate volume increases for the MIGC system are primarily due to throughput from contracts entered into by our affiliate upon expiration of two third-party contracts in December 2008 and January 2009, which enabled an affiliate of Anadarko to increase its volumes, and a new affiliate contract that became effective in September 2007 in connection with expansion of the system s capacity.

Third-party gathering and transportation throughput decreased by 13 MMcf/d for the year ended December 31, 2009 and increased by 58 MMcf/d for the year ended December 31, 2008. The decrease for the year ended December 31, 2009 is primarily attributable to throughput decreases at the MIGC system, partially offset by third-party throughput increases at the Haley and Pinnacle systems. The declines experienced on the MIGC pipeline were primarily due to the expiration of two third-party contracts described above. The throughput increases on the Haley system were primarily due to third-party drilling activity which partially offset natural production declines. The increase in third-party throughput at the Pinnacle system is primarily due to changes in contract terms mentioned above resulting in a shift from affiliate to third-party throughput. The increase for the year ended December 31, 2008 is primarily attributable to throughput increases at the Hugoton and Haley systems primarily from third-party drilling activity, partially offset by third-party throughput decreases at the Pinnacle system resulting primarily from natural production declines.

Affiliate processing throughput increased by 104 MMcf/d and 234 MMcf/d for the year ended December 31, 2009 and for the year ended December 31, 2008, respectively, and third-party processing throughput increased by 9 MMcf/d and by 18 MMcf/d for the year ended December 31, 2009 and for the year ended December 31, 2008, respectively. Affiliate throughput increased primarily due to increased throughput at the Chipeta plant from initial start-up of the plant in early 2008 and the addition of the cryogenic train in April 2009, driven by our affiliates drilling activities in the Natural Buttes area.

Equity investment volumes increased by 8 MMcf/d and by 28 MMcf/d for the year ended December 31, 2009 and for the year ended December 31, 2008, respectively, primarily due to additional throughput from the Powder River area following expansion of the Fort Union system during the second half of 2008.

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Natural Gas Gathering, Processing and Transportation Revenues

	2009	2008	Δ	2007	Δ
	(In thousands, except percentages)				
Gathering, processing and transportation of natural gas:					
Affiliates	$ 134,832	$ 121,389	11%	$ 93,007	31%
Third parties	16,984	17,475	(3)%	11,019	59%
Total	$ 151,816	$ 138,864	9%	$ 104,026	33%

Total gathering, processing and transportation of natural gas revenues increased by $13.0 million and by $34.8 million for the year ended December 31, 2009 and for the year ended December 31, 2008, respectively. Revenues from affiliates increased by $13.5 million for the year ended December 31, 2009 primarily due to increased affiliate throughput at the Chipeta plant following completion of the cryogenic unit in April 2009, increased throughput at the MIGC system due to the third-party contract expirations that caused volumes and associated revenues to shift from third party to affiliate and higher rates at the Haley system due to changes in contract terms, partially offset by throughput decreases at the Pinnacle, Dew, Hugoton and Haley systems. Gathering, processing and transportation of natural gas revenues from affiliates increased by $28.4 million for the year ended December 31, 2008 primarily due to increased throughput at the Chipeta plant after completion of the refrigeration unit in December 2007, increased throughput at the MIGC system and higher rates at the Dew, Haley and Pinnacle systems due to new contract terms, partially offset by throughput decreases at the Haley, Pinnacle, Dew and Hugoton systems.

Revenues from third parties decreased by $0.5 million for the year ended December 31, 2009, primarily due to third-party throughput decreases at the MIGC system attributable to the third-party contract expirations described above, partially offset by throughput increases at the Haley and Pinnacle systems. Revenues from third parties increased by $6.5 million for the year ended December 31, 2008 primarily due to increased third-party throughput at the Haley and Hugoton systems and higher gathering rates at the Haley system.

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Natural Gas, Natural Gas Liquids and Condensate Sales

	2009	2008	Δ	2007	Δ
		(In thousands, except percentages and average price per unit)			
Natural gas sales:					
Affiliates	$ 29,805	$ 64,844	(54)%	$ 42,302	53%
Third parties	8	23	(65)%		nm(1)
Total	$ 29,813	$ 64,867	(54)%	$ 42,302	53%
Natural gas liquids sales:					
Affiliates	$ 46,484	$ 107,304	(57)%	$ 96,795	11%
Third parties		159	(100)%		nm
Total	$ 46,484	$ 107,463	(57)%	$ 96,795	11%
Drip condensate sales:					
Affiliates	$	$	0%	$ 7,054	(100)%
Third parties	7,454	16,096	(54)%	2,772	481%
Total	$ 7,454	$ 16,096	(54)%	$ 9,826	64%
Total natural gas, natural gas liquids and condensate sales:					
Affiliates	$ 76,289	$ 172,148	(56)%	$ 146,151	18%
Third parties	7,462	16,278	(54)%	2,772	487%
Total	$ 83,751	$ 188,426	(56)%	$ 148,923	27%
Average price per unit:					
Natural gas (per Mcf)	$ 3.31	$ 7.45	(56)%	$ 5.36	39%
Natural gas liquids (per barrel)	$ 40.48	$ 74.90	(46)%	$ 57.10	31%
Drip condensate (per barrel)	$ 49.21	$ 89.34	(45)%	$ 64.43	39%

(1) Percent change is not meaningful

Total natural gas, NGL and condensate sales decreased by $104.7 million for the year ended December 31, 2009 and increased by $39.5 million for the year ended December 31, 2008. The decrease for the year ended December 31, 2009 consisted of a $61.0 million decrease in NGL sales, a $35.1 million decrease in natural gas sales and an $8.6 million decrease in drip condensate sales. The increase for the year ended December 31, 2008 consisted of a $22.5 million increase in natural gas sales, a $10.7 million increase in NGL sales and a $6.3 million increase in drip condensate sales.

The decrease in natural gas sales for the year ended December 31, 2009 was primarily due to a $4.14 per Mcf, or 56%, decrease in the average price for natural gas sold, partially offset by an approximate 1.1 MMcf, or 14%, increase in the volume of natural gas sold. The increase in natural gas sales for the year ended December 31, 2008 was primarily due to a $2.09 per Mcf, or 39%, increase in the average price of residue sold as volumes remained relatively flat.

The decrease in NGL sales for the year ended December 31, 2009 was primarily due to a $34.42 per barrel (or Bbl), or 46%, decrease in the average price for NGLs sold and an approximate 264,000 Bbls, or 18%, decrease in the volume of NGLs sold, primarily due to the suspension of operations of a plant at the Hilight system in September 2008 at which butane was purchased, processed into iso-butane and sold. The average natural gas and NGL prices for the year ended December 31, 2009 include $4.1 million of gains from commodity price swap agreements. The decrease in the NGL price per Bbl is due to the decrease in market prices, partially offset by the fixed prices at the Hilight and Newcastle systems under the commodity price swap agreements. The fixed prices under the swap agreements for 2009 were lower than 2008 market prices but higher than 2009 market prices. The increase in NGL sales for the year ended December 31, 2008 was primarily due to a $17.80 per Bbl, or 31%, increase in the average price of NGLs sold, partially offset by an approximate 227,000 Bbls, or 13%, decrease in the volume of NGLs sold.

The decrease in drip condensate sales for the year ended December 31, 2009 was primarily due to a $40.13 per Bbl, or 45%, decrease in average prices for drip condensate sold. Conversely, the increase for the year ended December 31, 2008 was due to a $24.91 per Bbl, or 39%, increase in the average price for condensate.

Equity Income and Other Revenues

	2009	2008	Δ	2007	Δ
	(In thousands, except percentages)				
Equity income affiliate	$ 6,982	$ 4,736	47%	$ 4,017	18%
Other revenues, net:					
Affiliates	$ 1,595	$ 4,552	(65)%	$ 2,127	114%
Third parties	975	7,928	(88)%	2,400	230%
Total equity income and other revenues, net	$ 9,552	$ 17,216	(45)%	$ 8,544	101%

Total equity income and other revenues decreased by $7.7 million for the year ended December 31, 2009 and increased by $8.7 million for the year ended December 31, 2008. During the year ended December 31, 2009, equity income from affiliates increased by approximately $2.2 million primarily from the system expansion at Fort Union and a decrease in that joint venture s interest expense. During the year ended December 31, 2008, equity income from affiliates increased $0.7 million primarily due to increased throughput.

For the year ended December 31, 2009, other affiliate and third-party revenues decreased primarily due to changes in gas imbalance positions and related gas prices and $1.9 million volume deficiency and indemnity payments from two third parties during 2008. For the year ended December 31, 2008, the increase is primarily due to changes in our natural gas imbalance positions due to higher gas prices and the indemnity payment received from a third party during 2008.

Cost of Product and Operation and Maintenance Expenses

	2009	2008	Δ	2007	Δ
	(In thousands, except percentages and price per unit)				
Cost of product	$ 51,136	$ 140,010	(63)%	$ 112,282	25%
Operation and maintenance	45,901	50,828	(10)%	40,756	25%
Total cost of product and operation and maintenance expenses	$ 97,037	$ 190,838	(49)%	$ 153,038	25%
Cost of product average price per unit:					
Natural gas (per Mcf)	$ 2.36	$ 6.22	(62)%	$ 3.72	67%
Natural gas liquids (per Bbl)	$ 18.87	$ 48.07	(61)%	$ 44.06	9%
Drip condensate (per MMBtu)	$ 3.26	$ 6.94	(53)%	$ 6.09	14%

Cost of product expense decreased by $88.9 million for the year ended December 31, 2009 and increased by $27.7 million for the year ended December 31, 2008. The decrease for the year ended December 31, 2009 includes an approximate $76.3 million decrease in cost of product expense attributable to the lower cost of natural gas and NGLs we purchase from producers due to lower market prices and lower volumes, a $5.2 million decrease due to changes in gas imbalance positions and related gas prices and a $3.7 million decrease from the lower cost of natural gas to compensate shippers on a thermally equivalent basis for drip condensate retained by us and sold to third parties, primarily due to lower market prices. For the year ended December 31, 2009, the volume of natural gas purchased from producers increased 14% and the volume of NGLs purchased from producers decreased 18%. The decrease in the volume of NGLs purchased is primarily due to the September 2008 suspension of operations of a plant that produced iso-butane from NGLs at the Hilight system. Excluding the impact of the plant suspension, the volume of NGLs purchased would have increased approximately 16%. The value of natural gas volumes that are purchased by us to return to producers under keep-whole arrangements are recorded as cost of product expense. The increase in the volumes of NGLs purchased, excluding the impact of the plant suspension, and the increase in the volumes of natural gas purchased are primarily due to the increase in throughput at the Chipeta plant for the year ended December 31, 2009 as well as increased NGL recoveries at the Chipeta plant due to completion of the cryogenic unit in April 2009.

Cost of product expense for the year ended December 31, 2008 increased by $27.7 million, $16.9 million of which was attributable to the higher cost of natural gas and NGLs we purchased from producers, primarily due to higher market prices. In addition, cost of product expense increased $6.6 million due to a change in imbalance positions and related gas prices and increased $3.1 million due to an unfavorable change in the difference between actual versus contractual fuel recoveries. The volume of natural gas purchased from producers remained relatively flat and the volume of NGLs purchased from producers decreased 13% for the year ended December 31, 2008. The decrease in the volume of NGLs purchased is primarily due to the September 2008 suspension of operations of a plant at the Hilight system. Excluding the impact of the plant suspension, the volume of NGLs purchased would have increased approximately 13%. This increase in the volumes of NGLs purchased, excluding the impact of the plant suspension, is primarily due to the increase in throughput at the Chipeta plant which was placed in service in December 2007.

Operation and maintenance expense decreased by $4.9 million for the year ended December 31, 2009 and increased by $10.1 million for the year ended December 31, 2008. The decrease for the year ended December 31, 2009 is primarily due to a $2.8 million decrease in operating fuel costs attributable to the plant suspension at the Hilight system in September 2008; a $1.2 million decrease in compressor parts and rental expenses primarily due to the contribution of previously leased compression equipment to us in November 2008; and lower rates on equipment rentals as a result of renegotiating with suppliers, partially offset by a $0.8 million increase in operating expenses at the Chipeta plant.

Operation and maintenance expense increased by $10.1 million for the year ended December 31, 2008 primarily due to a $6.5 million increase in labor and employee-related expenses 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 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 for our initial assets that became effective in January 2008; thus, our revenues increased by 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. Operating expenses also increased by $6.0 million due to operating expenses attributable to the Chipeta plant, partially offset by a $2.6 million decrease in compressor rental expenses.

Key Performance Metrics

	2009	2008	Δ	2007	Δ
	(In thousands, except percentages and gross margin per Mcf)				
Gross margin					
Gross margin	$ 193,983	$ 204,496	(5)%	$ 149,211	37%
Gross margin per Mcf(1)	$ 0.38	$ 0.41	(7)%	$ 0.37	11%
	$ 0.40	$ 0.42	(5)%	$ 0.37	14%

Gross margin per Mcf attributable to Western Gas Partners, LP(2)					
Adjusted EBITDA(3)	$ 111,160	$ 124,457	(11)%	$ 91,831	36%
Distributable cash flow(3)	$ 102,176	$ 117,277	(13)%		

(1) Calculated as gross margin (total revenues less cost of product), divided by total throughput, including 100% of gross margin and volumes attributable to Chipeta and our 14.81% interest in income and volumes

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attributable to Fort Union. Calculating gross margin per Mcf separately for affiliates and third parties is not meaningful since a significant portion of throughput is delivered from third parties while the related residue gas and NGLs are sold to an affiliate.

(2) Calculated as gross margin (total revenues less cost of product), excluding the noncontrolling interest owners proportionate share of revenues and cost of product, divided by total throughput attributable to Western Gas Partners, LP. Calculation includes income and volumes attributable to our investment in Fort Union.

(3) For a reconciliation of Adjusted EBITDA and distributable cash flow to their most directly comparable financial measures calculated and reconciliations to measures presented in accordance with GAAP, please read the caption *How We Evaluate Our Operations* within this *Item 7.*

Gross margin decreased by $10.5 million for the year ended December 31, 2009 and increased $55.3 million for the year ended December 31, 2008. The decrease in gross margin for year ended December 31, 2009 is primarily due to the decrease in natural gas and NGL prices and throughput. The impact of the decrease in market prices on our gross margin for the year ended December 31, 2009 was mitigated by our fixed-price contract structure. The increase in gross margin for the year ended December 31, 2008 is primarily due to the increase in natural gas and NGL prices and throughput.

Gross margin per Mcf attributable to Western Gas Partners, LP decreased by 5% and increased by 14% for the year ended December 31, 2009 and for the year ended December 31, 2008, respectively, and gross margin per Mcf decreased by 7% and increased by 11% for the year ended December 31, 2009 and for the year ended December 31, 2008, respectively. The 7% decrease in gross margin per Mcf for the year ended December 31, 2009 is primarily due to lower processing margins and lower drip condensate margins. The 11% increase in gross margin per Mcf for the year ended December 31, 2008 is primarily due to higher processing margins and higher drip condensate margins.

Adjusted EBITDA. Adjusted EBITDA decreased by $13.3 million for the year ended December 31, 2009 and increased by $32.6 for the year ended December 31, 2008. The decrease for the year ended December 31, 2009 is primarily due to a $101.6 million decrease in total revenues, excluding equity income; a $2.3 million increase in general and administrative expenses, excluding non-cash equity-based compensation and expenses in excess of the omnibus cap; and a $3.0 million increase in the noncontrolling interest owners share of Adjusted EBITDA; partially offset by a $88.9 million decrease in cost of product; a $4.9 million decrease in operation and maintenance expenses and a $0.4 million increase in distributions from Fort Union. The increase in Adjusted EBITDA for the year ended December 31, 2008 is primarily due to a $82.3 million increase in total revenues, excluding equity income, and an approximately $3.8 million increase in distributions from Fort Union, partially offset by a $27.7 million increase in cost of product, a $10.1 million increase in operation and maintenance expenses, a $9.4 million increase in the noncontrolling interest owners share of Adjusted EBITDA and a $5.1 million increase in general and administrative expenses, excluding non-cash equity-based compensation.

Distributable cash flow. Distributable cash flow decreased by $15.1 million for the year ended December 31, 2009 primarily due to the $13.3 million decrease in Adjusted EBITDA and a $9.6 million increase in interest expense settled in cash, partially offset by a $6.2 million increase in interest income and a $1.6 million decrease in maintenance capital expenditures. We did not utilize a distributable cash flow measure prior to becoming a publicly traded partnership in 2008 and, as such, did not differentiate between maintenance and capital expenditures prior to 2008 and do not present distributable cash flow for periods prior to 2008.

General and Administrative, Depreciation and Other Expenses

	2009	2008	Δ	2007	Δ
	(In thousands, except percentages)				
General and administrative	$ 20,136	$ 15,345	31%	$ 8,365	83%
Property and other taxes	7,251	6,760	7%	5,591	21%
Depreciation and amortization	40,065	36,042	11%	30,785	17%
Impairment		9,354	nm(1)		nm(1)
Total general and administrative, depreciation and other expenses	$ 67,452	$ 67,501	0%	$ 44,741	51%

(1) Percent change is not meaningful

General and administrative, depreciation and other expenses were flat for the year ended December 31, 2009 as a $4.8 million increase in general and administrative expenses combined with a $4.0 million increase in depreciation and amortization expense were substantially offset by a $9.4 million decrease in impairment expense. General and administrative expenses increased primarily due to incurring expenses attributable to being a publicly traded partnership for all of 2009, compared to approximately seven and a half months during the year ended December 31, 2008, and due to accounting and legal expenses attributable to the Chipeta acquisition. Depreciation and amortization expense increased for the year ended December 31, 2009 primarily due to assets placed in service during 2008 and 2009, including the Chipeta plant expansion completed in April 2009. Impairment expense for the year ended December 31, 2008 consisted of expense related to the suspension of operations of the plant at the Hilight system prior to our acquisition of the Powder River assets.

General and administrative, depreciation and other expenses increased by $22.7 million for the year ended December 31, 2008. General and administrative expenses increased by $7.0 million for the year ended December 31, 2008, primarily due to incurring $3.0 million of expenses attributable to being a publicly traded partnership during and subsequent to May 2008, $2.2 million attributable to equity-based compensation and $1.5 million of accounting and legal expenses attributable to the Powder River acquisition, partially offset by a decrease in expenses charged pursuant to the management services fee prior to our acquisition of the Partnership assets. Depreciation and amortization expense increased by $5.3 million for the year ended December 31, 2008 due to depreciation on assets placed in service in 2008 and 2007, primarily attributable to the Chipeta plant placed in serviced in December 2007, our Pinnacle Bethel treating facility completed in July 2008 and previously leased Hugoton compression equipment contributed to us in November 2008. Impairment expense for the year ended December 31, 2008 consisted of the $9.4 million charge recognized in connection with the plant suspension at the Hilight system.

Interest Income, Net

	2009	2008	Δ	2007	Δ
	(In thousands, except percentages)				
Interest income (expense), net affiliates					
Interest income on note receivable from Anadarko	$ 16,900	$ 10,703	58%	$	nm(1)

Interest expense on notes payable to Anadarko		(8,953)		(253)	nm			nm
Interest expense, net				(1,148)	(100)%		(7,805)	(85)%
Credit facility fees		(143)		(111)	29%			
Total	$	7,804	$	9,191	(15)%	$	(7,805)	nm
Interest expense third parties								
Credit facility interest, fees and amortization	$	(859)	$		nm	$		nm
Interest income (expense), net	$	6,945	$	9,191	(24)%	$	(7,805)	nm

(1) Percent change is not meaningful

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Interest income, net for the year ended December 31, 2009, consisted of interest income on our $260.0 million note receivable from Anadarko entered into in connection with our initial public offering in May 2008, partially offset by interest expense attributable to our $175.0 million term loan agreement entered into with Anadarko in connection with the Powder River acquisition; interest expense attributable to our $101.5 million term loan agreement entered into with Anadarko in connection with the Chipeta acquisition in July 2009 and repaid in October 2009; interest expense attributable to our revolving credit facility from October to December 2009; and commitment fees on our $350.0 million credit facility, $100.0 million portion of Anadarko s $1.3 billion credit facility and our $30.0 million working capital facility. Interest income, net for the year ended December 31, 2008 consisted of interest income on our $260.0 million note receivable from Anadarko, partially offset by interest expense on affiliate balances and commitment fees for our credit facilities. Interest expense on affiliate balances decreased for the year ended December 31, 2008 primarily due to the settlement of intercompany balances attributable to our initial assets in connection with our May 2008 initial public offering.

Income Tax Expense

	2009	2008	Δ	2007	Δ
	(In thousands, except percentages)				
Income before income taxes	$ 87,617	$ 95,554	(8)%	$ 55,894	71%
Income tax expense (benefit)	12	13,988	(100)%	19,424	(28)%
Effective tax rate	0%	15%		35%	

The Partnership is not a taxable entity for U.S. federal income tax purposes. With respect to the initial assets, income earned prior to May 14, 2008 was subject to federal and state income tax while income earned on or after May 14, 2008 was subject only to Texas margin tax. Similarly, with respect to the Powder River assets, income earned prior to December 19, 2008, was subject to federal and state income tax while income earned on or after December 19, 2008 was subject only to Texas margin tax. Income attributable to the Chipeta assets was subject to federal and state income tax for periods prior to June 1, 2008, at which time substantially all of the Chipeta assets were contributed to a non-taxable entity for U.S. federal income tax purposes.

Income tax expense decreased by $14.0 million and by $5.4 million for the year ended December 31, 2009 and for the year ended December 31, 2008, respectively. The decrease in income tax expense for the year ended December 31, 2009 is primarily due to a change in the applicability of U.S. federal income tax to our income that occurred in connection with the initial public offering, the Powder River acquisition and the June 2008 formation of the Chipeta partnership, as well as a decrease in Texas Margin tax expense attributable to the initial assets. In addition, our estimated income attributed to Texas relative to our total income decreased as compared to the prior year, which resulted in an approximately $0.6 million reduction of previously recognized deferred taxes during 2009. Income tax expense decreased for the year ended December 31, 2008 primarily due to a change in the applicability of U.S. federal income tax to our income described above, partially offset by income tax expense attributable to the Chipeta assets for the first five months of 2008.

For 2008 and 2009, our variance from the federal statutory rate is primarily attributable to our U.S. federal income tax status as a non-taxable entity, partially offset by state income tax expense.

Noncontrolling Interests

	2009	2008	Δ	2007	Δ
	(In thousands, except percentages)				
Net income (loss) attributable to noncontrolling interests	$ 10,260	$ 7,908	30%	$ (92)	nm(1)

(1) Percent change is not meaningful

Net income attributable to noncontrolling interests increased by $2.4 million and $8.0 million for the year ended December 31, 2009 and for the year ended December 31, 2008, respectively. Noncontrolling interests represent the aggregate 49% interest in Chipeta held by Anadarko and a third party. The increase in net

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income attributable to noncontrolling interests for the year ended December 31, 2009 is primarily due to higher throughput at the Chipeta plant, partially offset by lower NGL prices. The increase for the year ended December 31, 2008 is primarily due to an increase in volumes processed at the Chipeta plant as the refrigeration unit was placed in service in late 2007 and throughput increased to the plant s initial capacity during the first quarter of 2008. The cryogenic unit was placed in service in April 2009, leading to further increased volumes and NGL recoveries during the balance of 2009.

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* of this annual report.

Prior to our initial public offering, our sources of liquidity included cash generated from operations and funding from Anadarko. Furthermore, we 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 prior to our acquisition of the Partnership Assets were settled on a net basis through an adjustment to parent net investment. 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 by Anadarko.

Our sources of liquidity as of December 31, 2009 include:

- approximately $61.8 million of working capital, which we define as the amount by which current assets exceed current liabilities;
- cash generated from operations;
- available borrowings under our $350.0 million revolving credit facility, which is expandable to $450.0 million;
- available borrowings of up to $100.0 million under Anadarko s $1.3 billion 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; and
- potential issuances of additional partnership securities.

We believe that cash generated from these sources will be sufficient to satisfy our short-term working capital requirements and long-term maintenance 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.

On January 29, 2010, we borrowed $210.0 million under our $350.0 million revolving credit facility in connection with the Granger acquisition. See *Note 13 Subsequent Events Granger Acquisition* of the notes to the consolidated financial statements under *Item 8* of this annual report.

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 the level and timing of our 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 flows from operating activities, investing activities and financing activities as well as Adjusted EBITDA for the years ended December 31, 2009 and 2008.

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, 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 subsequent to December 19, 2008, with respect to the Powder River assets, transactions with Anadarko and third parties are cash-settled. Prior to June 1, 2008 with respect to Chipeta, sales and purchases related to third-party transactions were received or paid in cash by Anadarko within its centralized cash management system and were settled with Chipeta through an adjustment to parent net investment. Subsequent to June 1, 2008, Chipeta cash-settled transactions directly with third parties and with Anadarko affiliates.

	2009	2008	Δ	2007	Δ
	(In thousands, except percentages)				
Net cash provided by (used in):					
Operating activities	$ 113,958	$ 145,430	(22)%	$ 73,223	99%
Investing activities	(164,007)	(542,586)	(70)%	(143,274)	279%
Financing activities	83,959	433,230	(81)%	69,593	523%
Net increase (decrease) in cash and cash equivalents	$ 33,910	$ 36,074	(6)%	$ (458)	nm(1)

(1) Percent change is not meaningful

Operating Activities. Net cash provided by operating activities decreased by $31.5 million and increased by $72.2 million for the year ended December 31, 2009 and for the year ended December 31, 2008, respectively. For the year ended December 31, 2009, the decrease is primarily attributable to changes in working capital, lower throughput and gross margins, and higher general and administrative expenses as described in *Results of Operations Overview* above. In addition, these items were partially offset by lower current income taxes, and lower operations and maintenance expenses. For the year ended December 31, 2008, the increase in cash provided by operating activities 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, partially offset by higher cash operating expenses.

Investing Activities. Net cash used in investing activities decreased by $378.6 million for the year ended December 31, 2009 and increased by $399.3 million for the year ended December 31, 2008, respectively. Net cash used in investing activities for the year ended December 31, 2009 includes the $101.5 million cash consideration paid for the Chipeta acquisition. Net cash used in investing activities for the year ended December 31, 2008 includes our $260.0 million loan made to Anadarko in connection with our initial public offering and $175.0 million cash consideration paid for the Powder River acquisition. Investing cash flows included contributions to Fort Union of $8.1 million during the year ended December 31, 2008 related to the system expansion.

Capital expenditures decreased by $37.3 million and $37.4 million for the year ended December 31, 2009 and for the year ended December 31, 2008, respectively. Capital expenditures include costs attributable to the Chipeta assets prior to the Chipeta acquisition and include the noncontrolling interest owners share of Chipeta s capital expenditures.

Expansion capital expenditures decreased by 44%, from $82.0 million during the year ended December 31, 2008 to $46.1 million during the year ended December 31, 2009, primarily due to capital expenditures during the full year ended December 31, 2008 for the Chipeta plant construction compared to capital expenditures for the cryogenic unit during the first six months of 2009, completion of the NGL pipeline at the tailgate of the Chipeta plant during the second quarter of 2008, expansion of the Bethel facility completed during 2008 and installation of a compressor station at the Hugoton system during 2008, offset by the acquisition of the Natural Buttes plant during the fourth quarter of 2009. In addition, maintenance capital expenditures decreased by 8%, from $17.5 million during the year ended December 31, 2008 to

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$16.1 million during the year ended December 31, 2009, primarily due to fewer well connections at the Haley, Hugoton and Pinnacle systems due to reduced drilling activity, partially offset by a compression overhaul at our Hugoton System, an upgrade to the control system at the Hilight facility and equipment replacements at the Bethel facility during 2009. We did not differentiate between maintenance and capital expenditures for the year ended December 31, 2007. Capital expenditures decreased by $37.4 million for the year ended December 31, 2008 primarily due to completion of the Chipeta refrigeration unit in December 2007, partially offset by expansion of the Chipeta plant cryogenic train during 2008 and expansion of the Bethel facility and installation of the compressor station at the Hugoton system during 2008.

Financing Activities. Net cash provided by financing activities decreased by $349.3 million for the year ended December 31, 2009 and increased by $363.6 million for the year ended December 31, 2008. Proceeds from financing activities during the year ended December 31, 2009 included $122.5 million from the 2009 equity offering as well as the July 2009 issuance and October 2009 repayment of the three-year term loan to Anadarko originally incurred in connection with the Chipeta acquisition, partially offset by $4.3 million of costs paid in connection with the revolving credit facility we entered into in October 2009. The term loan was refinanced in October 2009 with borrowings on our revolving credit facility, then such revolving credit facility borrowings were repaid in December 2009 with a portion of the net proceeds from our 2009 equity offering. Net cash provided by financing activities for the year ended December 31, 2008 included the receipt of $315.2 million of net proceeds from our initial public offering, partially offset by a $45.2 million reimbursement to Anadarko of offering proceeds. Proceeds from financing activities for the year ended December 31, 2008 also included $175.0 million from the issuance of the five-year term loan to Anadarko in connection with the Powder River acquisition.

For the year ended December 31, 2009, $70.1 million of cash distributions were paid to our unitholders, representing distributions for the fourth quarter of 2008 through the third quarter of 2009. Distributions to unitholders totaled $24.8 million during the year ended December 31, 2008, representing the partial distribution for the second quarter of 2008 and a full distribution for the third quarter of 2008. Net contributions from Anadarko attributable to pre-acquisition intercompany balances were $3.5 million during the year ended December 31, 2009, representing the net non-cash settlement of intercompany transactions attributable to the Chipeta assets, compared to net distributions to Anadarko of $4.4 million for the year ended December 31, 2008, representing the net settlement of transactions attributable to the Powder River assets and Chipeta assets.

Financing proceeds for the year ended December 31, 2009 and for the year ended December 31, 2008 included $40.3 million and $55.4 million, respectively, of cash contributions from noncontrolling interest owners and Parent attributable to the Chipeta plant construction, for which the associated capital expenditures are included in investing activities above. Most of these contributions were received by Chipeta prior to our July 2009 acquisition of a 51% interest in Chipeta. Distributions from Chipeta to noncontrolling interest owners and Parent totaled $8.0 million and $37.9 million during the years ended December 31, 2009 and 2008, respectively, representing the distribution of Chipeta s available cash. Distributions to noncontrolling interest owners and Parent during the year ended December 31, 2008 included a $19.7 million one-time distribution of part of the consideration paid by the third-party owner following the initial formation of Chipeta.

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, reduce costs, increase revenues or increase gathering, processing, treating and transmission throughput or capacity from current levels, including well connections that increase existing system volumes.

Total capital incurred for the year ended December 31, 2009 and 2008 was $51.8 million and $108.6 million, respectively. Capital incurred is presented on an accrual basis. Capital expenditures in the consolidated statement of cash flows reflect capital expenditures on a cash basis, when payments are made. Capital expenditures for the years ended December 31, 2009 and 2008 were $62.2 million and $99.5 million, respectively. Capital expenditures for the year ended December 31, 2009 include $30.8 million attributable to the Chipeta assets prior to the Chipeta acquisition and include the noncontrolling interest owners share of Chipeta s capital expenditures which were funded by contributions from the noncontrolling interest owners. Expansion capital expenditures represented approximately 74% and 82% of total capital expenditures for the years ended December 31, 2009 and 2008, respectively. We estimate our total capital expenditures, excluding any future acquisitions, to be $28.0 million to $32.5 million and our maintenance capital expenditures to be approximately 75% to 80% of total capital expenditures for the year ending December 31, 2010. 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 our revolving credit facility or Anadarko s credit facility, the issuance of additional partnership units or debt offerings.

Distributions to unitholders. We expect to pay a quarterly distribution of $0.33 per unit per full quarter, which equates to approximately $21.4 million per full quarter, or approximately $85.6 million per full year, based on the number of common, subordinated and general partner units outstanding as of March 1, 2010. Our partnership agreement requires that we distribute all of our available cash (as defined in the partnership agreement) to unitholders of record on the applicable record date. During the year ended December 31, 2009, we paid cash distributions to its unitholders of approximately $70.1 million, representing the $0.32 per unit distribution for the quarter ended September 30, 2009, $0.31 per unit distribution for the quarter ended June 30, 2009 and $0.30 per unit distributions for each of the quarters ended March 31, 2009 and December 31, 2008. On January 21, 2010, the board of directors of our general partner declared a cash distribution to our unitholders of $0.33 per unit, or $21.4 million in aggregate, for the fourth quarter of 2009. The cash distribution was paid on February 12, 2010 to unitholders of record at the close of business on February 1, 2010.

Revolving credit facility. On October 29, 2009, we entered into a three-year senior unsecured revolving credit facility. The aggregate initial commitments of the lenders under this revolving credit facility are $350.0 million and are expandable to a maximum of $450.0 million. The revolving credit facility matures on October 29, 2012 and bears interest at LIBOR plus applicable margins ranging from 2.375% to 3.250%. We are also required to pay a quarterly facility fee ranging from 0.375% to 0.750% of the commitment amount (whether used or unused), based upon our consolidated leverage ratio as defined in the revolving credit facility.

The revolving credit facility contains various covenants that limit, among other things, our, and certain of our subsidiaries , ability to incur additional indebtedness, grant certain liens, merge, consolidate or allow any material change in the character of its business, sell all or substantially all of our assets, make certain transfers, enter into certain affiliate transactions, make distributions or other payments other than distributions of available cash under certain conditions and use proceeds other than for partnership purposes. If we obtain two of the following three ratings: BBB-or better by Standard and Poor s, Baa3 or better by Moody s Investors Service or BBB- or better by Fitch Ratings Ltd. (the date of such ratings being the Investment Grade Rating Date), we will no longer be required to comply with certain of the foregoing covenants. The revolving credit facility also contains 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) bankruptcy or insolvency of us or any material subsidiary; or (iii) a change of control.

All amounts due by us under the revolving credit facility are unconditionally guaranteed by certain of our wholly owned subsidiaries. The subsidiary guarantees will automatically terminate on the Investment Grade Rating Date.

On October 30, 2009, we used $100.0 million of our capacity under the revolving credit facility along with $2.0 million of cash on hand to refinance our $101.5 million, 7.00% fixed-rate, three-year term loan and settle related accrued interest. We entered into the three-year term loan agreement with Anadarko in July 2009 to finance a portion of the Chipeta acquisition. In December 2009, we repaid the amount outstanding under the revolving credit facility using a portion of the proceeds from the 2009 equity offering. In January 2010, we borrowed $210.0 million under the revolving credit facility to partially fund the Granger acquisition.

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 utilize 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. At December 31, 2009, 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, 2009, 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, if any) that Anadarko incurs under its credit facility, or up to $0.1 million annually. Under certain of Anadarko s credit and lease agreements, we 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, 2009, we and Anadarko were in compliance with all covenants. Should we or Anadarko fail to comply with any covenant in Anadarko s credit facilities, we may not be permitted to borrow thereunder. Anadarko is a guarantor of our borrowings, if any, under the credit facility. We are not a guarantor of Anadarko s borrowings under the credit facility.

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, 2009, no borrowings were outstanding under the working capital facility. The facility is available exclusively to fund working capital needs. 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 and monitor 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, NGLs 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 with respect to the initial assets. Finally, we entered into commodity price swap agreements with Anadarko in order to substantially reduce our exposure to

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commodity price risk attributable to our percent-of-proceeds and keep-whole 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, 2009:

	Office Lease	Asset Retirement Obligations	Note Payable to Anadarko Principal	Note Payable to Anadarko Interest	Credit Facility Fees	Total
			(In thousands)			
2010	$ 145	$	$	$ 7,000	$ 1,872	$ 9,017
2011	147			5,119	1,860	7,126
2012	5			5,119	1,558	6,682
2013			175,000	5,119	19	180,138
2014						
Thereafter		11,827				11,827
Total	$ 297	$ 11,827	$ 175,000	$ 22,357	5,309	$ 214,790

Office lease: 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.

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. The asset retirement obligation amounts above are discounted. 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* of this annual report.

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.

Credit Facility Fees: We are required to pay facility fees on our $350.0 million revolving credit facility, on our $100.0 million portion of Anadarko s $1.3 billion credit facility and on our $30.0 million working capital facility as described under the caption *Historical cash flow* above within this *Item 7.*

Also see the caption *Items Affecting the Comparability of Our Financial Results* under *Item 7* of this annual report 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 consolidated financial statements in accordance with GAAP requires our management to make informed judgments and estimates that affect the amounts of assets and liabilities as of the date of the financial statements and affect the amounts of revenues and expenses recognized during the periods reported. On an ongoing basis, management reviews its estimates, including those related to the determination of properties and equipment, goodwill, asset retirement obligations, litigation, environmental liabilities, income taxes and fair values. Although these estimates are based on management s best available knowledge of current and expected future events, changes in facts and circumstances or discovery of new information may result in revised estimates and actual results may differ from these estimates. Management considers the following to be its most critical accounting estimates that involve judgment and discusses the selection and development of these estimates with the audit committee of our general partner. For additional information concerning our accounting policies, see the *Note 2 Summary of Significant Accounting Policies* of the notes to the consolidated financial statements included under *Item 8* of this annual report.

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 $4.8 million, which would result in a corresponding reduction in our operating income.

Impairment of tangible 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.

Impairment of goodwill. We evaluate whether goodwill has been impaired annually as of October 1, unless facts and circumstances make it necessary to test more frequently. Management has determined that we have one operating segment and two reporting units: (i) gathering and processing and (2) transportation. The carrying value of goodwill as of December 31, 2009 was $16.0 million and $4.8 million for the gathering and processing reporting unit and transportation reporting unit, respectively. Accounting standards require that goodwill be 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.

Because quoted market prices for our reporting units are not available, management must apply judgment in determining the estimated fair value of reporting units for purposes of performing the goodwill impairment test. Management uses information available to make these fair value estimates, including market multiples of Adjusted

EBITDA. Specifically, management estimates fair value by applying an estimated multiple to projected 2010 Adjusted EBITDA. Management considered the relatively few observable transactions in the market, as well as trading multiples for peers, to determine an appropriate multiple to apply against our projected Adjusted EBITDA. A lower fair value estimate in the future for any of our reporting units could result in a goodwill impairment. Factors that could trigger a lower fair-value estimate include sustained price declines, cost increases, regulatory or political environment changes, and other changes in market conditions such as decreased prices in market-based transactions for similar assets. Based on our most recent goodwill impairment test, we concluded that the fair value of each reporting unit substantially exceeded the carrying value of the reporting unit. Therefore, no goodwill impairment was indicated and no goodwill impairment has been recognized in these consolidated financial statements.

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 our 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 12 Commitments and Contingencies* included in the notes to the consolidated financial statements under *Item 8* of this annual report, which information is incorporated by reference.

RECENT ACCOUNTING DEVELOPMENTS

The information required for this item is provided under the caption *New Accounting Standards* in *Note 2 Summary of Significant Accounting Policies* included in the notes to the consolidated financial statements under *Item 8* of this annual report 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 and processing contracts. Pursuant to certain of our contracts, we retain and sell drip 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 drip condensate and our costs for this portion of our contractual arrangement depend on the price of natural gas. Historically, drip condensate sells at a price representing a discount to the price of NYMEX West Texas Intermediate crude oil.

In addition, certain of our processing services are provided under percent-of-proceeds and keep-whole agreements in which Anadarko is typically responsible for the marketing of the natural gas and NGLs. Under percent-of-proceeds agreements, we receive a specified percentage of the net proceeds from the sale of natural gas and NGLs. Under keep-whole agreements, we keep 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, we compensate 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. To mitigate our exposure to changes in

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commodity prices on these types of processing agreements, we entered into commodity price swap agreements with Anadarko with fixed commodity prices that extend through December 31, 2011, with an option to extend through 2013. In addition, to mitigate our exposure to changes in commodity prices on these types of processing agreements on the Granger assets we acquired in January 2010, we entered into commodity price swap agreements with Anadarko with fixed commodity prices that extend through 2014. For additional information on the commodity price swap agreements, see *Note 6 Transactions with Affiliates* and *Note 13 Subsequent Events Granger acquisition* included in the notes to the consolidated financial statements included under *Item 8* of this annual report

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 year ended December 31, 2009, a 10% change in the margin between drip condensate and natural gas would have resulted in an approximate $0.5 million, or less than 3%, change in operating income for the period.

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. If interest rates rise, our future financing costs will increase. Interest rates during 2008 and 2009 were low compared to historic rates. As of December 31, 2009, we had $350.0 million of credit available under our revolving credit facility, $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. On January 29, 2010, we borrowed $210.0 million under our revolving credit facility in connection with the Granger acquisition. Our borrowings, if any, under our revolving credit facility, Anadarko s credit facility or our working capital facility bear interest at variable rates. In addition, as of December 31, 2009, we owed $175.0 million to Anadarko under our five-year term loan we entered into in connection with the Powder River acquisition which bears interest at a fixed rate of 4.0% until December 2011 and at a floating rate thereafter. See *Note 11 Debt and Interest Expense* of the notes to the consolidated financial statements included in *Item 8* of this annual report.

We may incur additional debt in the future, either under the revolving credit facility, our $100.0 million borrowing capacity under Anadarko s existing credit facility, our $30.0 million working capital facility with Anadarko 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 annual report.

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

None

Item 9A. *Disclosure Controls and Procedures*

Evaluation of Disclosure Controls and Procedures. The Chief Executive Officer and Chief Financial Officer of the Partnership s general partner performed an evaluation of the partnership s disclosure controls and procedures. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Securities Exchange Act of 1934 is accumulated and communicated to the issuer s management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company s disclosure controls and procedures were effective as of December 31, 2009.

Management s Annual Report on Internal Control Over Financial Reporting. See *Management s Assessment of Internal Control Over Financial Reporting* under *Item 8* of this annual report.

Attestation Report of the Independent Registered Public Accounting Firm. See the *Report of Independent Registered Public Accounting Firm* under *Item 8* of this annual report.

Changes in Internal Control over Financial Reporting. There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) or in other factors during the fourth quarter of 2009, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

The certifications of our general partner s Principal Executive Officer and Principal Financial Officer required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this annual report.

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 as 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 NYSE, and the Securities Exchange Act of 1934, as amended, 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 under *Item 13* of this annual report. We reimburse Anadarko for allocated expenses of operational personnel who perform services for our benefit, and for certain direct expenses.

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Board Leadership Structure

Anadarko owns and controls our general partner and, within the limitations of our Partnership Agreement and applicable SEC and NYSE rules and regulations, also exercises broad discretion in establishing the governance provisions of our general partner s limited liability company agreement. Accordingly, our general partner s Board structure is established by Anadarko.

Although our general partner s current Board structure has separated the roles of Chairman and CEO, Anadarko may in the future combine those roles at its discretion. Our general partner s limited liability company agreement and our Corporate Governance Guidelines permit the roles of Chairman and CEO to be combined, and Mr. Gwin served as Chairman and CEO of our general partner from October 2009 to January 2010.

Directors and Executive Officers

The biographies of each of the directors below contain information regarding the person s service as a director, business experience, director positions held currently or at any time during the last five years, information regarding involvement in certain legal or administrative proceedings, if applicable, and the experiences, qualifications, attributes or skills that caused our general partner and its board of directors to determine that the person should serve as a director for the general partner. Also, in light of our strategic relationship with our sponsor, Anadarko, our general partner considers service as an Anadarko executive to be a meaningful qualification for service as a non-independent director of our general partner.

The following table sets forth information with respect to the directors and executive officers of our general partner as of March 1, 2010. Directors are appointed for a term of one year.

Name	Age	Position with Western Gas Holdings, LLC
Robert G. Gwin	46	Chairman of the Board
Donald R. Sinclair	52	President, Chief Executive Officer and Director
Benjamin M. Fink	39	Senior Vice President and Chief Financial Officer
Danny J. Rea	51	Senior Vice President and Chief Operating Officer
Amanda M. McMillian	37	Vice President, General Counsel and Corporate Secretary
Jeremy M. Smith	37	Vice President and Treasurer
Michael C. Pearl	38	Senior Vice President and Chief Financial Officer departed May 2009
R. A. Walker	53	Director
Milton Carroll	59	Director
Anthony R. Chase	54	Director
James R. Crane	56	Director
Charles A. Meloy	49	Director
Robert K. Reeves	52	Director
David J. Tudor	50	Director

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.

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Robert G. Gwin Age: 46 Houston, Texas Director since: August 2007 ***Not Independent*** Officer From: August 2007 to January 2010	***Biography/Qualifications*** Robert G. Gwin has served as a director of our general partner since August 2007 and has served as non-executive Chairman of the Board of our general partner since October 2009. He also served as Chief Executive Officer of our general partner from August 2007 to January 2010 and as President from August 2007 to September 2009. 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 from November 2002 to February 2006, Chief Executive Officer and President from November 2002 to November 2004, and Chief Financial Officer from 2000 to November 2004. 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.
Donald R. Sinclair Age: 52 Houston, Texas Director since: October 2009 ***Not Independent*** Officer Since: October 2009	***Biography/Qualifications*** Donald R. Sinclair has served as President and a director of our general partner since October 2009 and as Chief Executive Officer since January 2010. Prior to becoming President and a director of our general partner, Mr. Sinclair was a founding partner and served as President of Ceritas Energy, LLC, a midstream energy company headquartered in Houston with operations in Texas, Wyoming and Utah from February 2003 to September 2009. Earlier in his career, Mr. Sinclair was President of Duke Energy Trading and Marketing LLC, one of the nation s largest marketers of natural gas and wholesale electric power, and served as Chairman of the Energy Risk Committee for Duke Energy Corporation. Prior to joining Duke, Mr. Sinclair served as Senior Vice President of Tenneco Energy and as President of Tenneco Energy Resources. Previously, as one of the original principals and officers at Dynegy (formerly NGC Corporation), he served for eight years in various officer positions, including Senior Vice President and Chief Risk Officer where he was in charge of all risk management activities and commercial operations. Mr. Sinclair earned a Bachelor of Business Administration degree from Texas Tech University.

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Benjamin M. Fink Age: 39 Houston, Texas Officer since: May 2009	***Biography/Qualifications*** Benjamin M. Fink has served as the Senior Vice President and Chief Financial Officer of our general partner since May 2009. He was Director, Finance of Anadarko from April 2007 to May 2009, during which time he was responsible for principal oversight of the finance operations of an Anadarko subsidiary, Anadarko Algeria Company, LLC. From August 2006 to April 2007, he served as an independent financial consultant to Anadarko in its Beijing, China and Rio de Janeiro, Brazil offices. From April 2001 until June 2006, he held executive management positions at Prosoft Learning Corporation, including serving as its President and Chief Executive Officer from November 2004 until that company s sale in June 2006. In April 2006, to facilitate its acquisition by another company, Prosoft filed a prepackaged voluntary plan of reorganization. From 2000 to 2001 he co-founded and served as Chief Operating Officer and Chief Financial Officer of Meta4 Group Limited, an online direct marketer based in Hong Kong and Tokyo. Previously, he held positions of increasing responsibility at Prudential Capital Group and Prudential Asset Management Asia, where he focused on the negotiation, structuring and execution of private debt and equity investments. He holds a Bachelor of Science degree in Economics from the Wharton School of the University of Pennsylvania, and he is a Chartered Financial Analyst.
Danny J. Rea Age: 51 Houston, Texas Officer since: August 2007	***Biography/Qualifications*** Danny J. Rea has served as Senior Vice President and Chief Operating Officer of our general partner since August 2007 and as Vice President, Midstream of Anadarko since May 2007. He also served as a director of our general partner from August 2007 to September 2009. Previously, Mr. Rea served as Manager, Midstream Services of Anadarko 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 28 years at Anadarko. 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 Age: 37 Houston, Texas Officer since: January 2008	***Biography/Qualifications*** Amanda M. McMillian has served as Vice President, General Counsel and Corporate Secretary of our general partner since January 2008 and as Lead Counsel of Anadarko since March 2010. She previously served as Senior Counsel from January 2008 to March 2010 and 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.

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Jeremy M. Smith
Age: 37
Houston, Texas
Officer since:
August 2007

Biography/Qualifications

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
Age: 53
Houston, Texas
Director since:
August 2007
Not Independent

Biography/Qualifications

R. A. Walker has served as a director of our general partner since August 2007. He also served as non-executive Chairman of the Board of our general partner from August 2007 to September 2009. He has served Anadarko as President and Chief Operating Officer since February 2010 and as Chief Operating Officer since March 2009. Prior to these positions he 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. 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
Age: 59
Houston, Texas
Director since:
April 2008
Independent

Biography/Qualifications

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 also served as a director of EGL, Inc. from May 2003 until August 2007 and as a director of the general partner of DCP Midstream Partners, LP from December 2005 to December 2006. Mr. Carroll holds a Bachelor of Science degree in Industrial Technology from Texas Southern University.

Anthony R. Chase
Age: 54
Houston, Texas
Director since:
April 2008
Independent

Biography/Qualifications

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. He is Chairman and Chief Executive Officer of ChaseSource LP, a Houston-based staffing firm. He is also a consultant to Crest Investment Company a Houston-based private equity firm that develops business opportunities worldwide, and served as an Executive Vice President of Crest Investment Company from January 2009 until December, 2009. Prior to these positions, 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 and serves on that board s audit committee. 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 Bachelor of Arts, Masters of Business Administration and Juris Doctor degrees from Harvard University.

James R. Crane
Age: 56
Houston, Texas
Director since:
April 2008
Independent

Biography/Qualifications

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 also served on the board of HCC Insurance Holdings, Inc. from 1999 to November 2007. Mr. Crane holds a Bachelor of Science degree in Industrial Safety from the University of Central Missouri.

Charles A. Meloy
Age: 49
Houston, Texas
Director since:
February 2009
Not Independent

Biography/Qualifications

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. Mr. Meloy is a member of the Board of Directors of the Independent Producers of America Association.

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Robert K. Reeves
Age: 52
Houston, Texas
Director since:
August 2007
Not Independent

Biography/Qualifications

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 of Anadarko 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
Age: 50
Carmel, Indiana
Director since:
April 2008
Independent

Biography/Qualifications

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 17 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 SEC, and any exchange or othalign="bottom" BGCOLOR="#CFF0FC" style="padding-left:0pt;padding-Right:0.75pt;padding-Top:0.75pt;padding-Bottom:0pt;width:10.92%; border-top:solid 0.75pt #000000; border-bottom:solid 0.75pt #000000;white-space:nowrap;">

173,681

142,214

115,658

Gross profit

370,362

267,007

197,564

Operating expenses[1]:

Research and development

96,750

65,976

41,156

Sales and marketing

116,803

80,984

56,203

General and administrative

48,841

41,458

30,239

Total operating expenses

262,394

188,418

127,598

Operating income

107,968

78,589

69,966

Other income (expense), net

1,667

28

(2,780

)

Income before income taxes

109,635

78,617

67,186

Provision for income taxes

40,831

24,157

26,803

Net income

$

68,804

$

54,460

$

40,383

(1) Includes stock-based compensation as follows:

Cost of revenues:			
Cost of subscription services	$1,109	$563	$273
Cost of professional services and other	6,002	3,858	2,272
Research and development	11,937	7,249	3,844
Sales and marketing	13,271	6,861	3,221
General and administrative	8,479	5,727	4,715
Total stock-based compensation	$40,798	$24,258	$14,325

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	Fiscal Year Ended January 31,		
	2017	2016	2015
Consolidated Statements of Income Data:			
Revenues:			
Subscription services	79.8 %	77.3 %	74.4 %
Professional services and other	20.2	22.7	25.6
Total revenues	100.0	100.0	100.0
Cost of revenues:			
Cost of subscription services	17.3	17.4	17.6
Cost of professional services and other	14.6	17.4	19.4
Total cost of revenues	31.9	34.8	37.0
Gross profit	68.1	65.2	63.0
Operating expenses:			
Research and development	17.8	16.1	13.1
Sales and marketing	21.5	19.8	17.9
General and administrative	9.0	10.1	9.6
Total operating expenses	48.3	46.0	40.6
Operating income	19.8	19.2	22.4
Other income (expense), net	0.3	—	(0.9)
Income before income taxes	20.1	19.2	21.5
Provision for income taxes	7.5	5.9	8.6
Net income	12.6 %	13.3 %	12.9 %

Revenues

	Fiscal Year Ended January 31,			2017 to 2016 % Change	2016 to 2015 % Change
	2017	2016	2015		
	(dollar amounts in thousands)				
Revenues:					
Subscription services	$434,316	$316,314	$233,063	37%	36%
Professional services and other	109,727	92,907	80,159	18	16
Total revenues	$544,043	$409,221	$313,222	33	31
Percentage of revenues:					
Subscription services	80				