Western Gas Partners LP
Form 10-K
February 24, 2011

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended December 31, 2010**
	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)

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 þ No o

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K 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 þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the 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 $703.1 million on June 30, 2010 based on the closing price as reported on the New York Stock Exchange.

At February 18, 2011, there were 51,036,968 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, 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.

Cryogenic: The fractionation process in which liquefied gases, such as liquid nitrogen or liquid helium, are used to bring volumes to very low temperatures (below approximately –238°F) to separate natural gas liquids from natural gas. Through cryogenic processing, more natural gas liquids are extracted than when traditional refrigeration methods are used.

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.

Frac: The process of hydraulic fracturing, or the injection of fluids into the wellbore to create fractures in rock formations, stimulating the production of oil or gas.

Fractionation: The process of applying various levels of higher pressure and lower temperature to separate a stream of natural gas liquids into ethane, propane, normal butane, isobutane and natural gasoline.

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.

Hinshaw pipeline: A pipeline that has received exemptions from regulations pursuant to the Natural Gas Act. These pipelines transport interstate natural gas not subject to regulations under the Natural Gas Act.

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 liquid(s) or NGL(s): The combination of ethane, propane, normal butane, isobutane and natural gasolines that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.

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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.

Receipt point: The point where volumes are received by or into a gathering system, processing facility or transportation pipeline.

Re-frac: The repeated process of hydraulic fracturing.

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 point at which the hydrocarbons and water exit the ground.

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WESTERN GAS PARTNERS, LP

PART I

Items 1 and 2. *Business and Properties*

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, or NYSE, 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, processing, compressing, treating and transporting natural gas, condensate, natural gas liquids, or NGLs, and crude oil 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 prospective context, 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 conte refer (i) to the business 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 (ii) to Western Gas Partners, LP and its subsidiaries thereafter, combined with (a) the business and operations of MIGC LLC, the Powder River assets and the Granger assets, as described in *Acquisitions Powder River acquisition* and *Acquisitions Granger acquisition* below, since August 23, 2006; (b) the business and operations of the Chipeta assets and Wattenberg assets, as described in *Acquisitions Chipeta acquisition* and *Acquisitions Wattenberg acquisition* below, since August 10, 2006; and (c) the financial results of Anadarko Wattenberg Company, LLC, or AWC, including the 0.4% interest in White Cliffs Pipeline, LLC, or White Cliffs, since January 29, 2007, as described in *Acquisitions White Cliffs acquisition* below.

Anadarko or Parent refers to Anadarko Petroleum Corporation (NYSE: APC) and its consolidated subsidiaries, excluding the Partnership and Western Gas Holdings, LLC, our general partner. Affiliates refers to wholly owned and partially owned subsidiaries of Anadarko, excluding the Partnership, and also refers to Fort Union Gas Gathering, L.L.C., or Fort Union, and White Cliffs. 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. The Partnership and its subsidiaries are indirect subsidiaries of Anadarko.

Approximately two-thirds of our services are provided under long-term contracts with fee-based rates with the remainder provided under percent-of-proceeds and keep-whole contracts. We have entered into fixed-price swap agreements with Anadarko to manage the commodity price risk otherwise inherent in our percent-of-proceeds and keep-whole contracts. A substantial part of our business is conducted under long-term contracts with Anadarko.

We believe that one of our principal strengths is our relationship with Anadarko. Over 74% of our total natural gas gathering, processing and transportation throughput during the year ended December 31, 2010 was comprised of natural gas production owned or controlled by Anadarko. In addition and solely with respect to the Wattenberg gathering system and the gathering systems included in our initial assets, as described under *Acquisitions* below, 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 long 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, or the Exchange Act. 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 with the SEC, 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*.

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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, 2010, our assets consist of ten gathering systems, six natural gas treating facilities, six natural gas processing facilities, one NGL pipeline, one interstate pipeline that is regulated by the Federal Energy Regulatory Commission, or FERC, and non-controlling interests in a gas gathering system and a crude oil pipeline. 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 and for the year ended December 31, 2010:

Area	Asset Type	Miles of Pipeline	Approximate Number of Receipt Points	Gas Compression (Horsepower)	Processing or Treating Capacity (MMcf/d)	Average Gathering, Processing and Transportation Throughput (MMcf/d)
Rocky Mountains [1]	Gathering, Processing and Treating	4,302	3,591	221,541	1,527	1,123
	Transportation	782	15	29,696		163
Mid-Continent	Gathering	1,953	1,549	91,105		109
East Texas	Gathering and Treating	588	820	37,875	502	319
West Texas	Gathering	118	90	560		114
Total		7,743	6,065	380,777	2,029	1,828

(1) Throughput includes 100% of Chipeta system volumes, excluding NGL pipeline volumes measured in barrels; 50% of Newcastle system volumes; 14.81% of Fort Union s gross volumes; and excludes crude oil throughput measured in barrels attributable to White Cliffs.

Our operations are organized into a single operating segment which engages in gathering, processing, compressing, treating and transporting Anadarko and third-party natural gas, condensate, NGLs and crude oil in the U.S. See *Item 8* of this annual report for disclosure of revenues, profits and total assets.

ACQUISITIONS

We have made the following acquisitions since our inception:

White Cliffs acquisition. In September 2010, we and Anadarko closed a series of related agreements through which we acquired a 10% member interest in White Cliffs. Specifically, the Partnership acquired Anadarko s 100% ownership interest in AWC for $20.0 million in cash. AWC owned a 0.4% interest in White Cliffs and held an option to increase its interest in White Cliffs. Also, in a series of concurrent transactions, AWC acquired an additional 9.6% interest in White Cliffs from a third party for $18.0 million in cash, subject to post-closing adjustments. White Cliffs owns a crude oil pipeline that originates in Platteville, Colorado and terminates in Cushing, Oklahoma and became operational in June 2009. The Partnership s acquisition of the 0.4% interest in White Cliffs and related purchase option from Anadarko is referred to as the AWC acquisition. The AWC acquisition and the acquisition of an additional 9.6% interest in White Cliffs were funded with cash on hand and are referred to collectively as the White Cliffs acquisition. The Partnership s interest in White Cliffs is referred to as the White Cliffs investment.

Wattenberg acquisition. In August 2010, we acquired certain midstream assets from Anadarko for (i) $473.1 million in cash, which was funded with $250.0 million of borrowings under an unsecured term loan, $200.0 million of borrowings under the Partnership s revolving credit facility and $23.1 million of cash on hand; as well as (ii) the issuance of 1,048,196 common units to Anadarko and 21,392 general partner units to our general partner. The assets acquired represent a 100% ownership interest in Kerr-McGee Gathering LLC, which owns the Wattenberg gathering system and related facilities, including the Fort Lupton processing plant. These assets, located in the Denver-Julesburg Basin, north and east of Denver, Colorado, are referred to collectively as the Wattenberg assets and the acquisition as the Wattenberg acquisition.

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, a 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. 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. In September 2010, we sold an idle refrigeration train at the Granger system to a third party for $2.4 million.

Chipeta acquisition. In July 2009, we acquired a 51% membership interest in Chipeta, together with an associated NGL pipeline, from Anadarko for consideration consisting of $101.5 million in cash, which was initially funded by a note from Anadarko, 351,424 common units and 7,172 general partner units. Chipeta owns a natural gas processing plant complex, which includes: 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 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 Colorado Interstate Gas Company (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.

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. We refer to these assets collectively as the Powder River assets and to the acquisition as the Powder River acquisition. Consideration for the Powder River acquisition consisted of $175.0 million in cash funded by a note from Anadarko, as well as 2,556,891 common units and 52,181 general partner units. The Powder River assets provide a combination of gathering, processing, compressing and treating services to customers in the Powder River Basin of Wyoming.

Initial assets acquisition. Concurrent with the May 2008 closing of our initial public offering (described below under *Equity Offerings*), 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.

Presentation of Partnership acquisitions. References to Partnership Assets refer collectively to the initial assets, Powder River assets, Chipeta assets, Natural Buttes plant, Granger assets, Wattenberg assets and White Cliffs investment. Unless otherwise noted, references to periods prior to our acquisition of the Partnership Assets and similar phrases refer to periods prior to May 2008 with respect to the initial assets, periods prior to December 2008 with respect to the Powder River assets, periods prior to July 2009 with respect to the Chipeta assets, periods prior to November 2009 with respect to the Natural Buttes plant, periods prior to January 2010 with respect to the Granger assets, periods prior to July 2010 with respect to the Wattenberg assets, and periods prior to September 2010 with respect to the White Cliffs investment. Reference to periods including and subsequent to our acquisition of the Partnership Assets and similar phrases refer to periods including and subsequent to May 2008 with respect to the initial assets, periods including and subsequent to December 2008 with respect to the Powder River assets, periods including and subsequent to July 2009 with respect to the Chipeta assets, periods subsequent to November 2009 with respect to the Natural Buttes plant, periods including and subsequent to January 2010 with respect to the Granger assets, periods including and subsequent to July 2010 with respect to the Wattenberg assets, and periods including and subsequent to September 2010 with respect to the White Cliffs investment.

Because Anadarko indirectly owns our general partner, each acquisition of Partnership Assets, except for the Natural Buttes plant and the acquisition of a 9.6% interest in White Cliffs from a third party, was considered a transfer of net assets between entities under common control. Accordingly, our consolidated financial statements include the financial results and operations of the Partnership Assets since the date of common control.

EQUITY OFFERINGS

Since its inception, the Partnership has completed the following public equity offerings:

November 2010 equity offering. On November 15, 2010, we closed a public offering of 7,500,000 common units at a price of $29.92 per unit. On November 22, 2010, we issued an additional 915,000 common units to the public pursuant to the partial exercise of the underwriters over-allotment option granted in connection with that offering. We refer to the November 15 and November 22, 2010 issuances collectively as the November 2010 equity offering. In connection with the November 2010 equity offering, we also issued 171,734 general partner units to our general partner. Net proceeds from the November 2010 equity offering of approximately $246.7 million were primarily used to repay amounts outstanding under our revolving credit facility.

May 2010 equity offering. On May 18, 2010, we closed a public offering of 4,000,000 common units at a price of $22.25 per unit. On June 2, 2010, we issued an additional 558,700 common units to the public pursuant to the exercise of the underwriters over-allotment option granted in connection with that offering. We refer to the May 18 and June 2, 2010 issuances collectively as the May 2010 equity offering. In connection with the May 2010 equity offering, we also issued 93,035 general partner units to our general partner. Net proceeds from the May 2010 equity offering of approximately $99.1 million were used to repay amounts outstanding under our 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. In connection with the 2009 equity offering, we also issued 140,817 general partner units to our general partner. Net proceeds from the 2009 equity offering of approximately $122.5 million were used to repay amounts outstanding under our revolving credit facility and to partially fund the Granger acquisition in January 2010.

Initial public offering. In May 2008, we closed our initial public offering of 18,750,000 common units at a price of $16.50 per unit. In June 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 and June 2008 issuances are referred to collectively as the initial public offering.

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 midstream service 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.

Managing commodity price exposure. We intend to continue limiting our direct exposure to commodity price changes. We actively seek to provide services under long-term fee-based agreements, and approximately two-thirds of our midstream services are provided under such 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, 2010, a 46.5% 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 flows. Our cash flows are 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.

Financial flexibility to pursue expansion and acquisition opportunities. During 2010, we acquired the Granger assets, Wattenberg assets and White Cliffs investment with a combination of borrowings under our revolving credit facility, a $250.0 million Wattenberg term loan provided by a group of banks and operating cash flows. During 2010, we raised $345.8 million of net proceeds through equity offerings, which we used to pay amounts outstanding under our revolving credit facility. As of December 31, 2010, we had $401.0 million of borrowing capacity available to us under our revolving credit facility, and expect to have approximately $100.0 million of borrowing capacity under our revolving credit facility after the closing of the Platte Valley acquisition described under the caption *Items Affecting the Comparability of Our Financial Results* within *Item 7* of this annual report. We believe our operating cash flows, borrowing capacity, and access to debt and equity capital markets provide us with the financial flexibility necessary to execute our strategy across capital-market cycles.

Substantial presence in liquids-rich basins. Our asset portfolio includes gathering and processing systems in areas in which the natural gas contains a significant content of NGLs, for which pricing is correlated to the price of crude oil as opposed to natural gas. Due to the relatively high current price of crude oil, production in these areas offers our customers higher margins and superior economics compared to basins in which the gas is predominantly dry. Drilling activity in liquids-rich areas is therefore less likely to decline in the current pricing environment than activity in dry gas areas, offering expansion opportunities for certain of our systems as producers attempt to increase their NGL production. For example, Anadarko has indicated it redirected its capital investment plans in 2010 and 2011 to target development in areas that offer higher liquids yields, or liquids-rich areas.

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Mature asset portfolio. Our asset portfolio currently has relatively low capital expenditure requirements. Total capital expenditures for the years ended December 31, 2010 and 2009 were $76.8 million and $74.6 million, respectively, including approximately $40.6 million and $24.7 million, respectively, of capital expenditures prior to our acquisition of the Partnership Assets. For the years ended December 31, 2010 and 2009, our expansion capital expenditures, including 51% of Chipeta s expenditures, were $53.1 million and $31.1 million, respectively, and our maintenance capital expenditures were $22.3 million and $23.9 million, respectively.

Well-positioned, well-maintained and efficient assets. We believe that our asset portfolio across diverse 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.

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 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, 2010, Anadarko indirectly held 1,583,128 general partner units representing a 2.0% general partner interest in the Partnership, 100% of the Partnership IDRs through its ownership of our general partner, and 10,302,631 common units and 26,536,306 subordinated units, which comprise an aggregate 46.5% limited partner interest in the Partnership. The public held 40,734,337 common units, representing a 51.5% 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 will have the ability, 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 hydrocarbon 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 smaller 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 gathered more efficiently and delivered into a higher pressure system, processing plant or pipeline. 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.*** Processing removes the heavier and more valuable hydrocarbon components, which are extracted as NGLs. The residue gas remaining after extraction of NGLs meets the quality standards for long-haul pipeline transportation or commercial use.
>
> ***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.

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. Under fee-based arrangements, the service provider typically receives a fee for each unit of natural gas gathered, treated and/or processed at its facilities. As a result, the price per unit received by the service provider does not vary with commodity price changes, minimizing the 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/or 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, NGLs and crude oil, 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, 2010, our assets consist of ten gathering systems, six natural gas treating facilities, six natural gas processing facilities, one NGL pipeline, one interstate pipeline, and noncontrolling interests in a gas gathering system and a crude oil pipeline. 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, 2010.

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Rocky Mountains

Wattenberg gathering system and processing plant. The Wattenberg gathering system is a 1,760-mile wet gas gathering system in the Denver-Julesburg Basin, north and east of Denver, Colorado, and includes seven compressor stations and 64,914 of operating horsepower. The Wattenberg processing plant has two trains with combined processing capacity of 139 MMcf/d.

Customers. Anadarko-operated production represents approximately 63% of system throughput during the year ended December 31, 2010. Approximately 31% of Wattenberg system throughput was from two third-party producers and the remaining throughput was from various third-party customers.

Supply. There are 1,999 receipt points connected to the gathering system as of December 31, 2010. The Wattenberg gathering system is primarily supplied by the Wattenberg field and covers portions of Adams, Arapahoe, Boulder, Broomfield and Weld counties. Anadarko controls approximately 684,000 acres in the Wattenberg field. The system is connected to over 4,500 wells. Anadarko drilled 371 wells and completed 1,777 fracs in connection with its active recompletion and re-frac program at the Wattenberg field during 2010 and has identified a five-year inventory of 4,000 to 5,000 opportunities to increase production including well locations, re-fracs and recompletions.

Delivery points. The Wattenberg gathering system has five delivery points. Primary delivery connections include BP Petroleum s Wattenberg processing plant, the Encana Oil & Gas (USA) Inc s, Platte Valley plant (formerly referred to as Encana s Fort Lupton plant) and our Fort Lupton processing plant. The two remaining delivery points are to DCP Midstream Partners, LP s, Spindle processing plant and AKA Energy s Gilcrest processing plant. All delivery points are connected to CIG and Xcel Energy residue gas pipelines, the ONEOK Overland Pass Pipeline for NGLs and have truck loading facilities for access to local NGL markets. BP s Wattenberg and Encana s Platte Valley processing plants also have NGL connections to the Weld Pipeline owned and operated by DCP (formerly the Buckeye Pipeline). We have entered into an agreement to purchase Encana s Platte Valley plant in the first quarter of 2011 as described under the caption *Items Affecting the Comparability of Our Financial Results* within *Item 7* of this annual report.

Granger gathering system and processing plant. The 815-mile natural gas gathering system and gas processing facility is located in Sweetwater County, Wyoming. The Granger system includes eight field compression stations with 41,950 horsepower. The processing facility has a cryogenic capacity of 200 MMcf/d and refrigeration capacity of 100 MMcf/d with NGL fractionation.

Customers. Anadarko is the largest customer on the Granger system with approximately 54% of throughput for the year ended December 31, 2010. The remaining throughput was primarily from five third-party shippers.

Supply. The Granger system is supplied by the Moxa Arch, the Jonah field and the Pinedale anticline in which Anadarko controls approximately 557,000 acres. The Granger gas gathering system has over 690 receipt points.

Delivery points. The residue gas from the Granger system can be delivered to five major pipelines including the CIG pipeline and also has access to two more pipelines through the Rendezvous Pipeline Company, a FERC-regulated Questar affiliate. The NGLs have market access to Enterprise s Mid-America Pipeline (MAPL), which terminates at Mont Belvieu, Texas, and local markets for purity products.

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 approximately 94% of the system throughput for the year ended December 31, 2010. The balance of throughput on the system during 2010 was from two third-party customers.

Supply. The Chipeta system is well positioned to access Anadarko and third-party production in the area with excess available capacity and is the only cryogenic processing facility in the Uintah Basin. Anadarko controls approximately 217,000 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 MAPL, 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 the following pipelines:

Questar Gas Management s pipeline to the Kern River market;

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.

Hilight gathering system and processing plant. The 1,105-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 has a capacity of approximately 30 MMcf/d and 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 gas compression, including one compressor station.

Customers. Gas gathered and processed through the Hilight system is purchased from numerous third-party customers, with the 9 largest producers providing approximately 71% of the system throughput during 2010.

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 plant delivers residue gas into MIGC s transmission line, which delivers to Glenrock, Wyoming. Hilight is not connected to an active NGL pipeline, so all fractionated NGLs are sold locally through its truck and rail loading facilities.

MIGC transportation system. The MIGC system is a 256-mile interstate pipeline regulated by FERC and operating within the Powder River Basin of Wyoming. 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 is certificated for 175 MMcf/d of firm transportation capacity.

Customers. Anadarko is the largest firm shipper on the MIGC system, with approximately 95% of throughput for the year ended December 31, 2010, with the remaining throughput from eleven 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. Most of our interruptible gas transportation agreements are month-to-month with the remainder generally having terms of less than one year.

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. Due to the commencement of operations of TransCanada s Bison pipeline in January 2011, the firm transportation contracts that expired at the end of January 2011 were not renewed. We monitor producer and marketing activities in the area served by our transportation system to identify new opportunities and to manage MIGC s throughput.

Supply. As of December 31, 2010, Anadarko has a working interest in over 1.7 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.

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Delivery points. MIGC volumes can be redelivered to three interstate market pipelines and one intrastate pipeline, including 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 Anadarko s MGTC intrastate pipeline, a Hinshaw pipeline that supplies local markets in Wyoming.

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 Coal. The Helper Field covers approximately 19,000 acres as of December 31, 2010 and Cardinal Draw Field, which lies immediately to the east of Helper Field, also covers approximately 20,000 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.

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. As of December 31, 2010, the Fort Union system produces gas from approximately 9,700 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 1.7 million gross acres within the Powder River Basin as of December 31, 2010. 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 U.S.

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, 2010. The remaining throughput on the system was from one third-party producer.

Supply. Clawson Springs Field has approximately 7,000 gross acres and produces primarily from the Ferron Coal.

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

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, 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 four producers providing approximately 90% of the system throughput during 2010. The largest producer, Black Hills Exploration, provided approximately 64% of the throughput during 2010.

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 Anadarko s MGTC pipeline for transport, distribution and sales.

White Cliffs pipeline. The White Cliffs pipeline consists of a 526-mile crude oil pipeline which originates in Platteville, Colorado and terminates in Cushing, Oklahoma. It has an approximate capacity of 30,000 Bpd which can be expanded to 50,000 Bpd. At the point of origin, it has a 100,000 barrel storage facility and a truck loading facility with an additional 20,000 barrels of storage. The pipeline is a joint venture owned by SemCrude Pipeline L.P. (51.0%), Plains Pipeline L.P. (34.0%), Noble Energy, Inc. (5.0%) and the Partnership (10.0%).

Customers. Approximately 54% and 38% of the White Cliffs pipeline throughput was from Anadarko and Noble Energy, respectively, for the year ended December 31, 2010.

Supply. The White Cliffs pipeline is supplied by production from the Denver-Julesburg Basin.

Delivery points. The White Cliffs pipeline delivery point is SemCrude s storage facility in Cushing, Oklahoma, a major crude oil marketing center, which ultimately delivers to the mid-continent refineries.

Mid-Continent

Hugoton gathering system. The 1,953-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 45 compressor stations with a combined 91,105 horsepower of compression.

Customers. Anadarko is the largest customer on the Hugoton gathering system with approximately 71% of the system throughput during the year ended December 31, 2010. Approximately 24% of the throughput on the Hugoton system for the year ended December 31, 2010 was from one third-party shipper with the balance consisting of various other third party shippers.

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 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.

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. Anadarko acquired a 49% interest in the Satanta plant in January 2011.

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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 provides 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 10 compressor stations with a combined 36,535 horsepower of compression.

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

Supply. As of December 31, 2010, Anadarko has approximately 836 producing wells in the Bossier play and controls approximately 139,000 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 265-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 LTD of sulfur treating capacity.

Customers. Anadarko is the largest shipper on the Pinnacle gathering system with approximately 89% of system throughput for the year ended December 31, 2010. Approximately 9% of throughput on the system during 2010 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. During 2008, in response to dedicated demand from a third party, we expanded the Bethel treating facilities by installing an additional 11 LTD of sulfur treating capacity to bring the total installed sulfur treating capacity to 20 LTD. 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.

West Texas

Haley gathering system. The 118-mile Haley gathering system provides gathering and dehydration services in Loving County, Texas and gathers a portion of Anadarko s production from the Delaware Basin.

Customers. Anadarko s production represented approximately 69% of the Haley gathering system s throughput for the year ended December 31, 2010. The remaining 31% of throughput is attributable to Anadarko s partner in the Haley area.

Supply. In the greater Delaware basin, Anadarko has access to approximately 346,000 gross acres as of December 31, 2010, a portion of which is gathered by the Haley gathering system.

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 and the Wattenberg gathering system. 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 midstream services business is very competitive. Our competitors include other midstream companies, producers, and intrastate and interstate pipelines. Competition for natural gas and NGL 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 Wattenberg, Granger, Hilight and Newcastle systems, which gather and process affiliate and/or third-party volumes, are their proximity to established and new production, and our ability to provide flexible services to producers. 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.

The following table summarizes the primary competitors for our gathering systems and processing plants.

System	Competitor(s)
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	MIGC, Thunder Creek Gas Services and TransCanada
Granger gathering system and processing plant	Williams Field Services, Enterprise/TEPPCO and Questar Gas Management
Haley gathering system	Anadarko s Delaware Basin Joint Venture, Enterprise GC, LP and Southern Union Energy Services Company
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
Newcastle gathering and processing system	DCP Midstream

Wattenberg gathering system and processing plant	DCP Midstream, BP Petroleum and Encana Natural Gas

Competition on transportation systems. 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. Competitive factors include commercial terms, available capacity, fuel efficiencies, the interconnected pipelines and gas quality issues. MIGC s major competitors are Thunder Creek Gas Services, TransCanada s Bison pipeline, which commenced operations in January 2011, and the Fort Union gathering system. The White Cliffs pipeline faces no direct competition from other pipelines, although shippers could sell crude oil in local markets rather than ship to Cushing, Oklahoma.

SAFETY AND MAINTENANCE

The pipelines we use to gather and transport natural gas and NGLs 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, as amended, or the NGPSA, with respect to natural gas and Hazardous Liquids Pipeline Safety Act of 1979, as amended, or the HLPSA, with respect to NGLs. Both the NGPSA and the HLPSA have been amended by the Pipeline Safety Improvement Act of 2002, or the PSIA, which was 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 natural gas and NGL 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 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 the following:

- 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 NGLs; 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.

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

Order No. 717-B, Order on Rehearing and Clarification was issued on November 16, 2009, but does not substantively affect the above discussion.

Order No. 717-C, Order on Rehearing and Clarification was issued on April 16, 2010. This Order clarifies the Commission s approach to determining whether certain employees execute transmission or marketing functions within an organization and clarifies certain exemptions to the no conduit rule, but does not substantively affect the above discussion.

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. Whether a pipeline s owners have actual or potential income tax liability will be reviewed by FERC on a case-by-case basis. How the policy statement affirmed by the D.C. Circuit is applied in practice to pipelines owned by publicly traded partnerships could impose limits on a pipeline s ability to include a full income tax allowance in its cost of service.

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.

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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 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 to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading or (3) 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 2007, 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. On December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Order No. 704 requires buyers and sellers of natural gas above a de minimis level, including entities not otherwise subject to FERC jurisdiction, to submit on May 1 of each year an annual report to FERC describing their aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. In June 2010, FERC issued an Order granting clarification regarding Order No. 704, and, in order to provide respondents time to implement new regulations related to Order No. 704, the FERC extended the deadline for calendar year 2009 until October 1, 2010. The due date of the report for calendar year 2010 and subsequent years remains May 1 of the following calendar year. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC s policy statement on price reporting. 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. On July 21, 2010, the FERC issued Order No. 720-B, which further clarified Order Nos. 720 and 720-A, but did not substantively alter the Orders requirements. On May 20, 2010, the FERC issued Order No. 735, which requires intrastate pipelines providing transportation services under Section 311 of the NGPA and Hinshaw pipelines operating under Section 1(c) of the NGA to report on a quarterly basis more detailed transportation and storage transaction information, including: rates charged by the pipeline under each contract; receipt and delivery points and zones or segments covered by each contract; the quantity of natural gas the shipper is entitled to transport, store, or deliver; the duration of the contract; and whether there is an affiliate relationship between the pipeline and the shipper. Order No. 735 further requires that such information must be supplied through a new electronic reporting system and will be posted on FERC s website, and that such quarterly reports may not contain information redacted as privileged. The FERC promulgated this rule after determining that such transactional information would help shippers make more informed purchasing decisions and would improve the ability of both shippers and the FERC to monitor actual transactions for evidence of market power or undue discrimination. Order No. 735 also extends the Commission s periodic review of the rates charged by the subject pipelines from three years to five years. Order No. 735 becomes effective on April 1, 2011. On December 16, 2010, the Commission issued Order No. 735-A. In Order No. 735-A, the Commission generally reaffirmed Order No. 735 requiring section 311 and Hinshaw pipelines to report on a quarterly basis storage and transportation transactions containing specific information for each transaction, aggregated by contract. Order No. 735-A did grant rehearing of three requests, including removing the requirement that the quarterly reports include the contract end-date for interruptible transactions, eliminating the increased per-customer revenue reporting requirements, and extending the deadline for submitting the quarterly reports from 30 days to 60 days following the quarter-end date. The Commission issued a Notice of Inquiry simultaneously with Order No. 735-A to consider issues related to existing semiannual storage reporting requirements for both interstate pipelines and section 311 and Hinshaw pipelines. One of the issues the Notice of Inquiry addresses is whether a change is warranted in the current per-customer storage revenue reporting requirement, including the confidentiality of that information.

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 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.

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

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

Pipeline safety legislation. Congress from time to time has considered legislation on pipeline safety and the U.S. Department of Transportation has announced a review of its safety rules and its intention to strengthen those rules. While we cannot predict the outcome of these legislative and regulatory initiatives, legislative and regulatory changes could have a material effect on our operations and could subject us to more comprehensive and stringent safety regulation and greater penalties for violations of safety rules.

Health care reform. In March 2010, the Patient Protection and Affordable Care Act, or PPACA, and the Health Care and Education Reconciliation Act of 2010, or HCERA, which makes various amendments to certain aspects of the PPACA, were signed into law. The HCERA, together with PPACA, are referred to as the Acts. Among numerous other items, the Acts reduce the tax benefits available to an employer that receives the Medicare Part D tax benefit, impose excise taxes on high-cost health plans, and provide for the phase-out of the Medicare Part D coverage gap. These changes are not expected to have a material impact on our financial condition, results of operations or cash flows.

Financial reform legislation. In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173) was signed into law. Among numerous other items, HR 4173 requires most derivative transactions to be centrally cleared and/or executed on an exchange, and additional capital and margin requirements will be prescribed for most non-cleared trades starting in 2011. Non-financial entities which enter into certain derivatives contracts are exempted from the central clearing requirement; however, (i) all derivatives transactions must be reported to a central repository, (ii) the entity must obtain approval of derivative transactions from the appropriate committee of its board and (iii) the entity must notify the Commodity Futures Trading Commission of its ability to meet its financial obligations before such exemption will be allowed. Additionally, financial institutions are required to spin off commodity, agriculture and energy swaps business into separately capitalized affiliates, which may reduce the number of available counterparties with whom the Partnership or Anadarko could contract. The Commodity Futures Trading

Commission has issued and requested comments on proposed regulations that set out the circumstances under which certain end users could elect to be exempt from the clearing requirements of HR 4173; however, the Partnership cannot predict at this time whether and to what extent any such exemption, once finalized in regulations, would be applicable to our activities. While we cannot currently predict the impact of this legislation, we will continue to monitor the potential impact of this new law as the resulting regulations emerge over the next several months and years.

ENVIRONMENTAL MATTERS

General. Our operation of pipelines, plants and other facilities to provide midstream services 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 the following:

- requiring the acquisition of various permits to conduct regulated activities;
- 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 condition, 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 and NGLs. 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 wastes. 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 wastes 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 or the legality of the original conduct, on certain classes of persons referred to as potentially responsible parties, or PRPs, and including 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, PRPs 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 Environmental Protection Agency or 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 PRPs. 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.

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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, or similar state statutes, 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 these hazardous waste laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We own or lease properties where petroleum 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 petroleum 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 petroleum 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 petroleum 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. 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 response to findings that emissions of carbon dioxide, methane, and other greenhouse gases, or GHG, present an endangerment to public heath and the environment because emissions of such gases are contributing to the warming of the earth s atmosphere and other climate changes, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that would require a reduction in emissions of GHG from motor vehicles and also may trigger construction and operating permit review for GHG emissions from certain stationary sources. The EPA has published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration, or PSD, and Title V permitting programs, pursuant to which these permitting programs have been tailored to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their

GHG emissions also will be required to reduce those emissions according to best available control technology standards for GHG that have yet to be developed. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. With regards to the monitoring and reporting of GHG, on November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule published in October 2009 to include onshore and offshore oil and natural gas production and onshore oil and natural gas processing, transmission, storage, and distribution activities, which may include certain of our operations, and to require the reporting of GHG emissions from covered facilities on an annual basis beginning in 2012 for GHG emissions occurring in 2011.

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In addition, Congress has from time to time considered legislation to reduce emissions of GHG, and numerous states have taken measures to reduce emissions of GHG. The adoption of any legislation or regulations that requires reporting of GHG or otherwise limits emissions of GHG from our equipment and operations could require us to incur costs to reduce emissions of GHG associated with our operations or could adversely affect demand for the natural gas and NGLs we gather and process.

Water. 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 may hold 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, 2010, Anadarko employed approximately 280 people who provided direct, full-time support to our operations. All of the employees required to conduct and support our operations are employed by Anadarko and all of our direct, full-time personnel are subject to a service and secondment agreement between our general partner and Anadarko. None of these employees are covered by collective bargaining agreements, and Anadarko considers its employee relations to be good.

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Item 1A. *Risk Factors*

CAUTIONARY NOTE REGARDING 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 by Partnership management, forward-looking statements concerning our operations, economic performance and financial condition. These statements can be identified by the use of forward-looking terminology including may, will, believe, expect, anticipate, estimate, continue, or other similar words. These statemen future expectations, contain projections of results of operations or financial condition or include other forward-looking information. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct.

These forward-looking statements involve 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 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 acquisitions, capital expenditures and other contractual obligations, and our ability to access those resources from Anadarko or through the debt or equity capital markets;

the supply of and demand for, and the prices 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 regulations; environmental risks; regulations by the Federal Energy Regulatory Commission, or FERC; and liability under federal and state laws and regulations;

changes in the financial or operational condition of our sponsor, Anadarko, including the outcome of the Deepwater Horizon events;

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

our commitments to capital projects;

the ability to utilize our revolving credit facility;

the creditworthiness of Anadarko or our other counterparties, including financial institutions, operating partners, and other parties;

our ability to repay debt;

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 of this annual report and in our other public filings and press releases.

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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 operations could be materially and adversely affected. In such case, the trading price of the common units could decline and you could lose all or part of your investment.

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RISKS RELATED TO OUR BUSINESS

We are dependent on Anadarko for a substantial 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 substantial majority of the natural gas that we gather, treat, process and transport. For the year ended December 31, 2010, Anadarko owned or controlled approximately 74% of our 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 production 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 are substantially dependent on Anadarko as our primary customer and general partner, any development that materially and adversely affects Anadarko s financial condition and/or its market reputation could have a material and adverse impact on us. Material adverse changes at Anadarko could restrict our access to capital, make it more expensive to access the capital markets and/or limit our access to borrowings on historically favorable terms.

We are substantially dependent on Anadarko as our primary customer and general partner and expect to derive a substantial majority of our revenues from Anadarko for the foreseeable future. As a result, any event, whether in our area of operations or otherwise, that adversely affects Anadarko s production, financial condition, leverage, market reputation, liquidity, results of operations or cash flows may adversely affect our revenues and cash available for distribution. 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;
- a reduction in or reallocation of Anadarko s capital budget, which could reduce the volumes available to us as a midstream operator to transport or process, limit our midstream opportunities for organic growth or limit the inventory of midstream assets we may acquire from Anadarko;
- its ability to replace reserves;
- its operations in foreign countries, which are subject to political, economic and other uncertainties;
- its drilling and operating risks, including potential environmental liabilities such as those associated with the Deepwater Horizon events, discussed below;
- transportation capacity constraints and interruptions;
- adverse effects of governmental and environmental regulation, including the ability to resume drilling operations in the Gulf of Mexico due to delays in the processing and approval of drilling permits and

exploration and oil spill-response plans; and

losses from pending or future litigation.

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Further, 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. 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.

Also, due to our relationship with Anadarko, our ability to access the capital markets, or the pricing we receive therein, may be adversely affected by any impairments to Anadarko s financial condition or adverse changes in its credit ratings. In June 2010, Moody s Investors Service, or Moody s, downgraded Anadarko s long-term debt rating from Baa3 to Ba1 and placed Anadarko s long-term ratings under review for further possible downgrade. Also in June 2010, Standard & Poor s, or S&P, affirmed its BBB- rating, but revised its outlook from stable to negative. At December 31, 2010, S&P and Fitch Ratings, or Fitch, continued to rate Anadarko s debt at BBB-, with a negative outlook. Moody s affirmed its Ba1 rating, but with a stable outlook at December 31, 2010.

Any material limitations on our ability to access capital as a result of such adverse changes at Anadarko could limit our ability to obtain future financing under favorable terms, or at all, or could result in increased financing costs in the future. Similarly, material adverse changes at Anadarko could negatively impact our unit price, limiting our ability to raise capital through equity issuances or debt financing, or could negatively affect our ability 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.

Please see *Item 1A*, in Anadarko s annual report on Form 10-K for the year ended December 31, 2010 for a full discussion of the risks associated with Anadarko s business.

Anadarko may incur significant costs and be subject to claims and liability as a result of the Deepwater Horizon events in the Gulf of Mexico.

Anadarko is a 25% non-operating interest owner in the well associated with the April 2010 explosion of the Deepwater Horizon drilling rig and resulting crude-oil spill into the Gulf of Mexico. The Deepwater Horizon events could result in Anadarko incurring potential environmental liabilities and sanctions, losses from pending or future litigation, reduced availability or increased cost of capital to fund future exploration and development, the tightening of or lack of access to insurance coverage for offshore drilling activities and adverse governmental and environmental regulations. The adverse resolution of matters related to the Deepwater Horizon events could subject Anadarko to significant contractual costs, monetary damages, fines and other penalties, which could have a material adverse effect on Anadarko s business, prospects, results of operations, financial condition and liquidity. Material losses by Anadarko could, among other things, impact our ability to access the capital markets, or the pricing we receive therein, and could also limit our opportunities for organic growth around Anadarko s production assets. If these events were to occur, 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.

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, 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 Anadarko or third parties.

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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, processing 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 $0.38 per unit per quarter, or $1.52 per unit per year, we will require available cash of approximately $30.6 million per quarter, or $122.3 million per year, based on the number of general partner units and common and subordinated units outstanding at February 18, 2011. 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, process, treat 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.

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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. For example, in recent years, market prices for natural gas have declined substantially from the highs achieved in 2008, and the increased supply resulting from the rapid development of shale plays throughout North America has contributed significantly to this trend. Factors impacting commodity prices include the following:

- domestic and worldwide economic conditions;
- weather conditions and seasonal trends;
- the ability to develop recently discovered or deploy new technologies to known natural gas fields;
- 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 or a market for exported 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 negatively impact our financial condition, thereby reducing our cash flows and our ability to make distributions to unitholders.

Based on gross margin for the year ended December 31, 2010, approximately 29% 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, condensate and NGLs. These percentages 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, condensate and NGLs. These strategies will vary in scope based upon the level and volatility of natural gas, condensate and NGL prices and other changing market conditions. We currently have in place fixed-price swap agreements with Anadarko expiring at various times through September 2015 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 the following instances:

- 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 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 if our lending counterparties become unwilling or unable to meet their funding obligations. 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 and Wattenberg term loan agreement 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 Wattenberg term loan agreement 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 and Wattenberg term loan agreement contain covenants, some of which may be modified or eliminated upon our receipt of an investment grade rating, that restrict or limit our ability to do the following:

- 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 and Wattenberg term loan agreement include financial leverage and interest coverage ratios. The terms of these agreements require us to maintain (i) a ratio of total debt to Consolidated Earnings Before Interest, Taxes, Depreciation and Amortization, or Consolidated EBITDA, as defined in the credit agreement and Wattenberg term loan agreement, of 4.5 or less and (ii) a ratio of Consolidated EBITDA, as defined in the credit agreement and Wattenberg term loan agreement, to interest expense of 3.0 or greater. As of December 31, 2010, we were in compliance with those covenants. See *Item 7* of this annual report for a further discussion of the terms of our revolving credit facility and Wattenberg term loan.

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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 flows 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 Wattenberg term loan agreement and revolving credit facility, 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.

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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 the following, 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 flows 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 flows and not solely on profitability, which will be affected by capital expenditures and non-cash items. As a result, we may make cash distributions for periods in which we record losses for financial accounting purposes and may not make cash distributions for periods in which we record net earnings for financial accounting purposes.

The amount of available cash we need to pay the distribution announced for the quarter ended December 31, 2010 on all of our units and the corresponding distribution on our general partner s 2.0% interest for four quarters is approximately $122.3 million.

We typically do not obtain independent evaluations of natural gas reserves connected to our 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.

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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 midstream systems that would create additional competition for the services we provide to our customers. In addition, our customers, including Anadarko, may develop their own midstream 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 flows 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, 2010, we had approximately $60.2 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 risk 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 impairments, and more frequently when circumstances indicate likely impairments, 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 we are unable to maintain the throughput on our 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 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 are connected 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 NGLs, or if the volumes we gather or transport do not meet the quality requirements of such pipelines or facilities, our revenues and cash available for distribution could be adversely affected.

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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. 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 the following:

- 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 NGLs; 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. The process is typically regulated by state oil and gas commissions. However, certain environmental groups have advocated that additional laws are needed to more closely and uniformly regulate the hydraulic fracturing process, and legislation was proposed in the recently ended session of Congress to provide for federal regulation of hydraulic fracturing as well as to require disclosure of the chemicals used in the fracturing process, and such legislation could be introduced in the current session of Congress. In addition, the EPA, recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act s Underground Injection Control Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA s recent decision. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example, New York has imposed a de facto moratorium on the issuance of permits for high-volume, horizontal hydraulic fracturing until state-administered environmental studies are finalized, a draft of which must be published by June 1, 2011

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followed by a 30-day comment period. Further, Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed and Wyoming has adopted legislation requiring drilling operators conducting hydraulic fracturing activities in that state to publicly disclose the chemicals used in the fracturing process. 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 systems. Such developments could materially adversely affect our revenues, results of operations and cash available for distribution.

Climate change legislation or regulatory initiatives could increase our operating and capital costs and could have the indirect effect of decreasing throughput available to our systems or demand for the products we gather, process and transport.

Following its determination that emissions of CO_2, methane and other greenhouse gases, or GHG, present an endangerment to public heath and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that establish motor vehicle GHG emission standards effective January 2, 2011 and also trigger, according to the agency, Prevention of Significant Deterioration, or PSD, and Title V permit requirements for stationary sources. Regulations adopted by the EPA have tailored the PSD and Title V permitting programs so that they apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to best available control technology standards for GHG that have yet to be developed. The EPA s rules relating to emissions of GHG from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing or requiring state environmental agencies to implement the rules. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities.

The EPA also recently published regulations on November 30, 2010 that require onshore and offshore oil and natural gas production and onshore oil and natural gas processing, transmission, storage, and distribution activities, which may include certain of our operations, to monitor and report GHG emissions from covered facilities on an annual basis, beginning in 2012 for GHG emissions occurring in 2011. In addition, Congress has from time to time considered legislation to reduce emissions of GHG, and numerous states have already taken legal measures to reduce emissions of GHG, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs.

The increased costs of operations or delays in drilling that could be associated with climate change legislation may reduce drilling activity by Anadarko or third-party producers in our areas of operation, with the effect of reducing the throughput available to our systems. Further, the adoption of any legislation or regulations that requires reporting of GHG or otherwise limits emissions of GHG from our equipment and operations could require us to incur costs to reduce emissions of GHG associated with our operations or could adversely affect demand for the natural gas and NGLs we gather and process. Such developments could materially adversely affect our revenues, results of operations and cash available for distribution.

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The U.S. Congress recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act, or HR 4173, which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Partnership or Anadarko, that participate in that market. The new legislation was signed into law by the President on July 21, 2010 and requires the Commodities Futures Trading Commission, or the CFTC, and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In its rulemaking under the new legislation, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalent. Certain bona fide hedging transactions or positions would be exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize these regulations. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our commodity price management activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require some counterparties to spin off some of their derivatives activities to separate entities, which may not be as creditworthy. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing commodity price contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of commodity price contracts as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and make cash distributions to our unitholders.

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 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.

We may incur significant costs and liabilities resulting from pipeline integrity programs and related repairs.

Pursuant to the Pipeline Safety Improvement Act of 2002, as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, the Department of Transportation, or the DOT, through the Pipeline and Hazardous Materials Safety Administration, or PHMSA, has adopted regulations requiring pipeline operators to develop integrity management programs for transmission pipelines located where a leak or rupture could do the most harm in high consequence areas, including high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release and commercially navigable waterways, unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. The regulations require the following of operators of covered pipelines to:

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

In addition, states have adopted regulations similar to existing DOT regulations for intrastate gathering and transmission lines. At this time, we cannot predict the ultimate cost of compliance with this regulation, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures or repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of our gathering and transmission lines.

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 statement 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. Whether a pipeline s owners have actual or potential income tax liability will be reviewed by FERC on a case-by-case basis. How the policy statement is applied in practice to pipelines owned by publicly traded partnerships could impose limits on our ability to include a full income tax allowance in cost of service.

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 master limited partnerships, or 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 revenues and cash available for distribution.

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

Our 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 following:

- the federal Clean Air Act and analogous state laws that impose obligations related to emissions of air pollutants;
- 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 Resource Conservation and Recovery Act, or 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 results of operations or financial condition. Finally, future federal and/or state restrictions, caps, or taxes on GHG emissions that may be passed in response to climate change or hydraulic fracturing concerns may impose additional capital investment requirements, increase our operating costs and reduce the demand for our services.

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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 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 affect 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 the Fort Union and White Cliffs entities 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 or White Cliffs 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.

Further, in connection with the acquisition of our 51% membership interest in Chipeta, we became party to Chipeta s limited liability company agreement, as amended and restated as of July 23, 2009. Among other things, the Chipeta LLC agreement provides that to the extent available, Chipeta will distribute available cash, as defined in the Chipeta LLC agreement, to its members quarterly in accordance with those members membership interests. Accordingly, we may be required to distribute a portion of Chipeta s cash balances, which are included in the cash balances in our consolidated balance sheets, to the other Chipeta members.

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 gathering, processing, compressing, treating and transporting natural gas, condensate and NGLs, including the following:

- 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, loss of life, pollution and/or 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 third-party customers, and any material non-payment or non-performance by these parties, including with respect to our gathering, processing and transportation agreements, 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 in 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.

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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.

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RISKS INHERENT IN AN INVESTMENT IN US

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

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

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

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

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

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

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

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

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

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

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

Our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period.

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.

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

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

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

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

Please read *Item 13* 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 Anadarko, which owns and controls our general partner, and its affiliates for all expenses they incur on our behalf as determined by our general partner pursuant to the omnibus agreement. These expenses include all costs incurred by Anadarko and our general partner in managing and operating us, as well as the reimbursement of incremental general and administrative expenses we incur as a result of being a publicly traded partnership. Our partnership agreement provides that Anadarko 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.

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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 were 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 our revolving credit facility 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 the following:

- 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 the 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 any of the following:

(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.

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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 its 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.

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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 February 18, 2011, Anadarko owns 47.5% 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 unitholders 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.

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

As of February 18, 2011, Anadarko holds an aggregate of 10,302,631 common units and 26,536,306 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and may convert earlier under certain circumstances. The sale of any or all of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market on which common units are traded.

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

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price. As a result, existing unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Existing unitholders may also incur a tax liability upon a sale of their units. As of February 18, 2011, Anadarko owns approximately 20.2% 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 47.5% 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.

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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 flows 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 the following:

- 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 Internal Revenue Service, or the IRS, were to treat us as a corporation for federal income tax purposes or if 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, nor do we plan to request, a ruling from the IRS on this or any other tax matter affecting us.

Despite the fact that we are 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 flows 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 is 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.

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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. Recently, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration 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 or any other matter affecting us. 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.

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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.

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.

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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. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. 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. The IRS has recently announced a relief procedure whereby a publicly traded partnership that has technically terminated may be permitted to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

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, federal, 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 Colorado, 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, except Wyoming, 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, regulatory or administrative proceedings other than proceedings arising in the ordinary course of our business. Management believes that there are no such proceedings for which final disposition could have a material adverse effect on our results of operations, cash flows or financial condition, or for which disclosure is otherwise required by Item 103 of Regulation S-K. 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.

Item 4. (Removed and 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. The following table sets forth the high and low sales prices of the common units as well as the amount of cash distributions declared and paid by quarter for the years ended December 31, 2010 and 2009.

	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
2010				
High Price	**$ 31.35**	**$ 27.17**	**$ 23.95**	**$ 23.50**
Low Price	**$ 27.12**	**$ 21.25**	**$ 19.78**	**$ 19.42**
Distribution per common and subordinated unit	**$ 0.38**	**$ 0.37**	**$ 0.35**	**$ 0.34**
2009				
High Price	$ 20.00	$ 17.99	$ 15.80	$ 16.65
Low Price	$ 17.11	$ 15.03	$ 13.22	$ 12.20
Distribution per common and subordinated unit	$ 0.33	$ 0.32	$ 0.31	$ 0.30

As of February 18, 2011, there were approximately 19 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 1,583,128 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. See the caption *Selected Information From Our Partnership Agreement* within this *Item 5*.

OTHER SECURITIES MATTERS

Sales of unregistered units. In connection with our May 2008 initial public offering, we issued 1,083,115 general partner units to our general partner, representing its initial 2.0% general partner interest in us, 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. In connection with our November 2010, May 2010 and 2009 follow-on equity offerings, our general partner purchased an additional 171,734 general partner units, 93,035 general partner units and 140,817 general partner units, respectively, to maintain its 2.0% general partner interest in us. In August 2010, we acquired the Wattenberg assets from Anadarko for consideration consisting of $473.1 million in cash, 1,048,196 common units and 21,392 general partner units. In January 2010, we acquired the Granger assets from Anadarko for consideration consisting of $241.7 million cash, 620,689 common units and 12,667 general partner units. In July 2009, we acquired the Chipeta assets from Anadarko for consideration consisting of $101.5 million cash, 351,424 common units and 7,172 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 common units and 52,181 general partner units. The common units, subordinated 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 pursuant to an exemption from registration under Section 4(2) of the Securities Act of 1933, as amended.

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*.

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, plus, at the discretion of the general partner, working capital borrowings made subsequent to the end of such 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. It is intended that working capital borrowings be repaid within 12 months. In all cases, working capital borrowings are used solely for working capital purposes or to fund distributions to partners.

Minimum quarterly distributions. The partnership agreement provides that, during a period of time referred to as the subordination period, the common units are entitled to distributions of available cash each quarter in an amount equal to the minimum quarterly distribution, which is $0.30 per common unit, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash are permitted on the subordinated units. Furthermore, arrearages do not apply to 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	$0.30	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 2.0% 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.

Item 6. *Selected Financial and Operating Data*

The following table shows our selected financial and operating data which are derived from our consolidated financial statements for the periods and as of the dates indicated. 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. In January 2010, August 2010 and September 2010, we closed the Granger acquisition, Wattenberg acquisition and AWC acquisition, respectively, and the assets and operations of the Granger assets, Wattenberg assets and 0.4% interest in White Cliffs. Anadarko acquired MIGC, the Powder River assets and the Granger assets in connection with its August 23, 2006 acquisition of Western and acquired the Chipeta assets and Wattenberg assets in connection with its August 10, 2006 acquisition of Kerr-McGee. Anadarko made its initial investment in White Cliffs on January 29, 2007.

Our acquisitions from Anadarko are considered transfers of net assets between entities under common control. Accordingly, our consolidated financial statements include (i) the combined financial results and operations of AGC and PGT from their inception through the closing date of our initial public offering and (ii) the consolidated financial results and operations of Western Gas Partners, LP and its subsidiaries from the closing date of our initial public offering thereafter, combined with (a) the financial results and operations of MIGC, the Powder River assets and Granger assets, from August 23, 2006 thereafter, (b) the financial results and operations of the Chipeta assets and Wattenberg assets, from August 10, 2006 thereafter, and (c) the 0.4% interest in White Cliffs from January 29, 2007 thereafter.

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

	2010	2009	2008	2007	2006
	Summary Financial Information (in thousands, except per unit data, throughput and gross margin per Mcf)				
Statement of Income Data (for the year ended):					
Total revenues	**$ 503,322**	$ 490,546	$ 698,768	$ 556,874	$ 216,197
Costs and expenses	**278,880**	295,625	461,736	361,975	146,924
Depreciation, amortization and impairments	**72,793**	66,784	71,040	58,867	32,699
Total operating expenses	**351,673**	362,409	532,776	420,842	179,623
Operating income	**151,649**	128,137	165,992	136,032	36,574
Interest income (expense), net	**(1,881)**	7,581	11,784	(5,667)	(9,476)
Other income (expense), net	**(2,123)**	62	199	52	304
Income tax expense (1)	**10,572**	17,614	43,747	46,012	8,559
Net income	**137,073**	118,166	134,228	84,405	18,843
Net income (loss) attributable to noncontrolling interests	**11,005**	10,260	7,908	(92)	
Net income attributable to Western Gas Partners, LP	**$ 126,068**	$ 107,906	$ 126,320	$ 84,497	$ 18,843
Key Performance Measures (for the year ended):					
Gross margin (2)	**$ 346,273**	$ 326,474	$ 365,886	$ 303,431	$ 129,372
Adjusted EBITDA (3)	**214,834**	185,103	229,926	192,231	68,654
Distributable cash flow (3)	**190,119**	168,132	201,250	n/a	n/a
General partner s interest in net income (4)	**3,067**	1,428	842	n/a	n/a
Limited partners interest in net income (4)	**111,064**	69,980	41,261	n/a	n/a
Net income per limited partner unit (basic and diluted) (4)	**$ 1.64**	$ 1.24	$ 0.78	n/a	n/a
Distributions per unit	**$ 1.39**	$ 1.23	$ 0.46	n/a	n/a
Balance Sheet Data (at period end):					
Property, plant and equipment, net	**$ 1,359,350**	$ 1,360,988	$ 1,364,438	$ 1,270,309	$ 1,147,016
Total assets	**1,765,537**	1,788,918	1,762,002	1,360,104	1,234,734
Total long-term liabilities	**518,275**	448,288	454,040	406,834	410,287
Total partners capital and equity	**$ 1,205,068**	$ 1,305,473	$ 1,239,586	$ 912,504	$ 799,845

Cash Flow Data (for the year ended):										
Net cash flows provided by (used in):										
Operating activities	**$**	**217,074**	$	164,870	$	216,795	$	155,480	$	49,798
Investing activities		**(824,341)**		(176,421)		(578,283)		(162,250)		(49,385)
Financing activities		**564,357**		45,461		397,562		6,312		41
Capital expenditures	**$**	**76,834**	$	74,588	$	135,188	$	154,850	$	49,385
Operating Data (volumes in MMcf/d):										
Gathering and transportation throughput		**1,031**		1,145		1,218		1,222		1,217
Processing throughput (5)		**681**		637		524		323		409
Equity investment throughput (6)		**116**		120		112		84		
Total throughput		**1,828**		1,902		1,854		1,629		1,626
Throughput attributable to noncontrolling interests		**197**		180		124				
Throughput attributable to Western Gas Partners, LP		**1,631**		1,722		1,730		1,629		1,626
Average gross margin per Mcf (7)	**$**	**0.52**	$	0.47	$	0.54	$	0.51	$	0.29
Average gross margin per Mcf attributable to Western Gas Partners, LP	**$**	**0.55**	$	0.49	$	0.56	$	0.51	$	0.29

(1) Income earned by the Partnership, a non-taxable entity for U.S. federal income tax purposes, including and subsequent to our acquisition of the Partnership Assets, except for the Chipeta assets, was subject only to Texas margin tax, while income earned prior to our acquisition of the Partnership Assets, except for the Chipeta assets, was subject to federal and state income tax. Income attributable to Chipeta was subject to federal and state income tax 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 under *Item 8* of this annual report.

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

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(3) Adjusted EBITDA and distributable cash flow are not defined in the U.S. generally accepted accounting principles, or 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 expansion capital expenditures prior to 2008.

(4) 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.

(5) Processing throughput includes 100% of Chipeta system volumes, excluding NGL pipeline volumes measured in barrels, and includes 50% of Newcastle system volumes.

(6) Equity investment throughput represents the Partnership s 14.81% share of Fort Union s gross volumes and excludes crude oil throughput measured in barrels attributable to White Cliffs.

(7) Calculated as gross margin divided by total throughput, including 100% of gross margin and volumes attributable to Chipeta, 14.81% interest in income and volumes attributable to Fort Union and 0.4% interest in income attributable to White Cliffs.

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

OVERVIEW

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

OPERATING AND FINANCIAL HIGHLIGHTS

Significant financial and operational highlights during the year ended December 31, 2010 include the following:

- During 2010, we issued an aggregate 12,973,700 common units in public offerings, generating net proceeds of $345.8 million, including the general partner s proportionate capital contributions to maintain its 2.0% general partner interest. Net proceeds from these offerings were used to repay amounts outstanding under our revolving credit facility.

- During 2010, we completed several acquisitions, including the August acquisition of the Wattenberg gathering system and Fort Lupton processing plant; the January acquisition of the Granger gathering system, which includes two cryogenic trains, one refrigeration train, one fractionation train and ancillary equipment; and the September acquisition of a 10% interest in White Cliffs.

- Our strong operating cash flows, combined with a focus on cost reduction and capital spending discipline, enabled us to raise our distribution to $0.38 per unit for the fourth quarter of 2010. This represents a 3% increase over the distribution for the third quarter of 2010, a 15% increase over the distribution for the fourth quarter of 2009 and our seventh consecutive quarterly increase.

- Gross margin (total revenues less cost of product) attributable to Western Gas Partners, LP averaged $0.55 per Mcf for the year ended December 31, 2010, representing a 12% increase compared to the year ended December 31, 2009. The increase in gross margin per Mcf for the year ended December 31, 2010 is primarily due to higher margins at the Wattenberg, Granger and Hilight systems and the change in throughput mix within our portfolio.

- Throughput attributable to Western Gas Partners, LP totaled 1,631 MMcf/d for the year ended December 31, 2010, representing a 5% decrease compared to the same period in 2009. The throughput decrease is primarily due to lower volumes at the Pinnacle, Haley, Dew and Hugoton systems due to natural production declines and low drilling activity. These declines were partially offset by increased throughput at the Chipeta, Granger and Wattenberg systems, driven by favorable producer economics in these areas due to the relatively high liquid content of the gas volumes produced.

Descriptions of acquisitions since our inception and our presentation of assets acquired are included under the caption *Acquisitions* under *Items 1 and 2* of this annual report.

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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 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 Partner or Western Gas Partners are intended to refer (i) to the business and operations of AGC and PGT from their inception through the closing date of our initial public offering and (ii) to Western Gas Partners, LP and its subsidiaries thereafter, combined with (a) the business and operations of MIGC, the Powder River assets and the Granger assets since August 23, 2006; (b) the business and operations of the Chipeta assets and Wattenberg assets since August 10, 2006; and (c) the financial results of AWC, including the 0.4% interest in White Cliffs, since January 29, 2007. Anadarko or Parent refers to Anadarko Petroleum Corporation and its consolidated subsidiaries, excluding the Partnership and the general partner. Affiliates refers to wholly owned and partially owned subsidiaries of Anadarko, excluding the Partnership, and also refers to Fort Union and White Cliffs.

References to the Partnership Assets refer collectively to the initial assets, Powder River assets, Chipeta assets, Granger assets, Wattenberg assets and the White Cliffs investment. Unless otherwise noted, references to periods prior to our acquisition of the Partnership Assets and similar phrases refer to periods prior to May 2008 with respect to the initial assets, periods prior to December 2008 with respect to the Powder River assets, periods prior to July 2009 with respect to the Chipeta assets, periods prior to January 2010 with respect to the Granger assets, periods prior to July 2010 with respect to the Wattenberg assets, and periods prior to September 2010 with respect to the White Cliffs investment. Unless otherwise noted, references to periods subsequent to our acquisition of the Partnership Assets and similar phrases refer to periods including and subsequent to May 2008 with respect to the initial assets, periods including and subsequent to December 2008 with respect to the Powder River assets, periods including and subsequent to July 2009 with respect to the Chipeta assets, periods including and subsequent to January 2010 with respect to the Granger assets, periods including and subsequent to July 2010 with respect to the Wattenberg assets, and periods including and subsequent to September 2010 with respect to the White Cliffs investment.

Our results are driven primarily by the volumes of natural gas and NGLs we gather, process, treat or transport through our systems. For the year ended December 31, 2010, approximately 84% of our total revenues and 74% of our throughput was attributable to transactions 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.

We received significant dedications from our largest customer, Anadarko, solely with respect to the gathering systems connected to the Wattenberg system and the gathering systems included in our initial assets. 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 long as additional wells are connected to these gathering systems.

For the year ended December 31, 2010, approximately 69% of our gross margin was attributed to fee-based contracts, under which a fixed fee is received based on the volume and thermal content of the natural gas we gather, process, 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. Fee-based gross margin includes equity income from our interests in Fort Union and White Cliffs. Certain of our fee-based contracts contain keep-whole provisions.

For the year ended December 31, 2010, approximately 29% of our gross margin was attributed to percent-of-proceeds and keep-whole contracts, pursuant to which we have commodity price exposure, including gross margin attributable to condensate sales. 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.

We also have indirect exposure to commodity price risk in that persistent low natural gas prices have caused and may continue to cause our current or potential customers to delay drilling or shut in production in certain areas, which would reduce the volumes of natural gas available for 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.

As a result of our initial public offering and subsequent acquisitions from Anadarko, the results of operations, financial position and cash flows may vary significantly for 2010, 2009 and 2008 as compared to future periods. 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, 2010, we added 106 receipt points to our systems with initial throughput of approximately 0.9 MMcf/d per receipt point.

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 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 purchases and sales of natural gas, condensate and NGLs 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, equipment rentals, 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 and the general partner on our behalf and allocations of general and administrative costs by Anadarko and the general partner 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 and the general partner incur 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 the following:

- 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, pursuant to the terms of the omnibus agreement with Anadarko, we are required 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 $9.0 million for the year ended December 31, 2010. The cap contained in the omnibus agreement expired on December 31, 2010 and did not apply to incremental general and administrative expenses incurred by or allocated to us as a result of being a separate publicly traded entity. Subsequent to December 31, 2010, general and administrative expenses allocated to us will be determined by Anadarko in its reasonable discretion, in accordance with the partnership agreement and the omnibus agreement. Public company expenses that were not subject to the cap contained in the omnibus agreement, excluding equity-based compensation, were $8.0 million, $7.5 million and $4.5 million for the years ended December 31, 2010, 2009 and 2008, respectively. See *Note 6 Transactions with Affiliates Omnibus agreement* of the notes to the consolidated financial statements under *Item 8* of this annual report.

Adjusted EBITDA. We define Adjusted EBITDA as net income (loss) attributable to Western Gas Partners, LP, plus distributions from equity investees, non-cash equity-based compensation expense, expense in excess of the omnibus cap, interest expense, income tax expense, depreciation, amortization and impairments, and other expense, less income from equity investments, interest income, income tax benefit, other income and other nonrecurring adjustments that are not settled in cash. 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 the following, 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 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.

Distributable cash flow should not be considered an alternative to net income, earnings per unit, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. 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 attributable to Western Gas Partners, LP. 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 attributable to Western Gas Partners, LP or net cash provided by operating activities. Adjusted EBITDA and distributable cash flow have important limitations as analytical tools because they exclude 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. Our definitions of Adjusted EBITDA and distributable cash flow may not be comparable to similarly titled measures of other companies in our industry, thereby diminishing their 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 (a) 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 (b) a reconciliation of the non-GAAP financial measure of distributable cash flow to the GAAP financial measure of net income attributable to Western Gas Partners, LP:

	Year Ended December 31,		
	2010	**2009**	**2008**
	(in thousands)		
Reconciliation of Adjusted EBITDA to net income attributable to Western Gas Partners, LP			
Adjusted EBITDA attributable to Western Gas Partners, LP	**$ 214,834**	$ 185,103	$ 229,926
Less:			
Distributions from equity investees	**5,935**	5,552	5,128
Non-cash equity-based compensation expense	**4,787**	3,580	1,924
Expenses in excess of omnibus cap	**133**	842	
Interest expense	**18,794**	9,955	364
Income tax expense (1)	**10,572**	17,614	43,690
Depreciation, amortization and impairments (1)	**69,972**	64,577	69,566
Other expense, net (1)	**2,126**		
Add:			
Equity income, net	**6,640**	7,330	4,736
Interest income affiliate	**16,913**	17,536	12,148
Other income, net (1)		57	182
Net income attributable to Western Gas Partners, LP	**$ 126,068**	$ 107,906	$ 126,320
Reconciliation of Adjusted EBITDA to net cash provided by operating activities			
Adjusted EBITDA attributable to Western Gas Partners, LP	**$ 214,834**	$ 185,103	$ 229,926
Adjusted EBITDA attributable to noncontrolling interests	**13,823**	12,462	9,422
Interest income (expense), net	**(1,881)**	7,581	11,784
Non-cash equity-based compensation expense	**(4,787)**	(3,580)	(1,924)
Current income tax expense	**(12,222)**	(21,677)	(45,350)
Other income (expense), net	**(2,123)**	62	199
Distributions from equity investees less than (in excess of) equity income, net	**705**	1,778	(392)
Expenses in excess of omnibus cap	**(133)**	(842)	
Changes in operating working capital:			
Accounts receivable and natural gas imbalance receivable	**339**	6,087	(3,888)
Accounts payable, accrued liabilities and natural gas imbalance payable	**10,936**	(20,071)	18,383
Other	**(2,417)**	(2,033)	(1,365)
Net cash provided by operating activities	**$ 217,074**	$ 164,870	$ 216,795

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

	Year Ended December 31, 2010	2009	2008
	(in thousands)		
Reconciliation of distributable cash flow to net income attributable to Western Gas Partners, LP			
Distributable cash flow	**$ 190,119**	$ 168,132	$ 201,250
Less:			
Distributions from equity investees	**5,935**	5,552	5,128
Non-cash equity-based compensation expense	**4,787**	3,580	1,924
Expenses in excess of omnibus cap	**133**	842	
Income tax expense (1)	**10,572**	17,614	43,690
Depreciation, amortization and impairments (1)	**69,972**	64,577	69,566
Other expense, net (1)	**2,126**		
Add:			
Equity income, net	**6,640**	7,330	4,736
Cash paid for maintenance capital expenditures (1)	**22,314**	23,916	39,015
Cash paid for income taxes	**507**		
Interest income, net (non-cash settled)	**13**	636	1,445
Other income, net (1)		57	182
Net income attributable to Western Gas Partners, LP	**$ 126,068**	$ 107,906	$ 126,320

(1) Includes the Partnership s 51% share of income tax expense; depreciation, amortization and impairments; other expense, net; cash paid for maintenance capital expenditures; and other income, net, attributable to Chipeta.

ITEMS AFFECTING THE COMPARABILITY OF OUR FINANCIAL RESULTS

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

Platte Valley acquisition agreement. In January 2011, we entered into an agreement to acquire the Platte Valley gathering system and processing plant from a third party for $303.3 million in cash, subject to closing adjustments. These assets are located in the Denver-Julesburg Basin and consist of (i) a processing plant with two cryogenic processing trains with a combined capacity of 84 MMcf/d and two fractionation trains with a combined capacity of 7,900 barrels per day; (ii) a 1,054-mile gathering system that delivers gas to the Platte Valley plant, either directly or through our Wattenberg gathering system; and (iii) related equipment. The Platte Valley gathering system and processing plant are referred to collectively as the Platte Valley assets and the acquisition as the Platte Valley acquisition. In connection with the acquisition, we will enter into long-term fee-based agreements with the seller to gather and process its existing natural gas production, as well as to expand the existing gathering systems and processing capacity to 100 MMcf/d. We intend to finance the Platte Valley acquisition with available capacity under our revolving credit facility. The acquisition is expected to close in the first quarter of 2011, subject to regulatory approval and customary closing conditions.

Affiliate contracts. Effective October 1, 2009, contracts covering substantially all of the Granger assets affiliate throughput were converted from primarily keep-whole contracts into a ten-year fee-based arrangement and, effective

July 1, 2010, contracts covering all of Wattenberg s affiliate throughput were converted from primarily keep-whole contracts into a ten-year fee-based agreement. These contract changes will impact the comparability of the statements of income and cash flows. See *Note 6 Transactions with Affiliates Gas processing agreements* in the notes to the consolidated financial statements under *Item 8* of this annual report.

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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 at the Hilight and Newcastle systems has been mitigated through our fixed-price commodity price swap agreements with Anadarko that extend through December 31, 2012, with a Partnership option to extend through 2013. Beginning January 1, 2010, commodity price swap agreements were put in place to fix the margin we realize under both keep-whole and percentage-of-proceeds contracts applicable to natural gas processing activities at the Granger assets. The commodity price swap arrangements for the Granger assets expire in December 2014. Beginning July 1, 2010, commodity price swap agreements were put in place to fix the margin we realize from the purchase and sale of natural gas, condensate or NGLs at the Wattenberg assets. The commodity price swap arrangements for the Wattenberg assets expire in June 2015. Beginning October 1, 2010, commodity price swap agreements were put in place to mitigate exposure to commodity price volatility associated with condensate and natural gas sales and purchases at the Hugoton system. The commodity price swap arrangements associated with the Hugoton system expire in September 2015. See *Note 6 Transactions with Affiliates* included in the notes to the consolidated financial statements included under *Item 8* of this annual report.

Federal income taxes. We are generally not subject to federal income tax or state income tax other than Texas margin tax on the portion of our income that is allocable to Texas. Federal and state income tax expense was recorded prior to our acquisition of the Partnership Assets, except for the Chipeta assets. In addition, deferred federal and state income taxes are recorded on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases with respect to the Partnership Assets prior to our acquisition of the Partnership Assets; and deferred state income taxes are recorded with respect to the Partnership Assets for periods including and subsequent to our acquisition. The recognition of deferred federal and state tax assets prior to our acquisition of the Partnership Assets was based on management s belief that it was more likely than not that the results of future operations would generate sufficient taxable income to realize the deferred tax assets. For periods including and subsequent to our acquisition of the Partnership Assets, except for the Chipeta assets, we are only subject to Texas margin tax; therefore, we no longer recognize deferred federal income tax assets and liabilities with respect to the Partnership Assets for periods including and subsequent to our acquisition of the Partnership Assets. Income tax expense attributable to Texas margin tax will continue to be recognized in our consolidated financial statements. Substantially all of the income attributable to the Chipeta assets prior to the June 2008 formation of Chipeta, at which time substantially all of the Chipeta assets were contributed to a non-taxable entity for U.S. federal income tax purposes, was subject to federal and state income taxes, while substantially all of the income earned by the Chipeta assets subsequent to June 2008 was subject only to Texas margin tax. Income attributable to the Granger assets prior to and including January 2010 was subject to federal income tax, and income attributable to the Wattenberg assets prior to and including July 2010 was subject to federal and state income tax. Income earned by the Granger assets and Wattenberg assets for periods subsequent to January 2010 and July 2010, respectively, was subject only to Texas margin tax. For periods including and subsequent to our acquisition of the Partnership Assets, we are required to make payments to Anadarko pursuant to a tax sharing agreement for our estimated share of non-U.S. federal taxes included in any combined or consolidated returns of Anadarko.

General and Administrative Expenses under the Omnibus Agreement. Pursuant to the omnibus agreement, Anadarko and the general partner perform 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, 2010, 2009 and 2008, Anadarko billed us $9.0 million, $6.9 million and $3.4 million, respectively, in allocated general and administrative expenses subject to the cap contained in the omnibus agreement. In addition, our general and administrative expenses for the years ended December 31, 2010 and 2009, included $0.1 million and $0.8 million, respectively, of expenses incurred by Anadarko and the general partner in excess of the cap contained in the omnibus agreement. Such expenses were recorded as capital contributions from Anadarko and did not impact the Partnership s cash flows. The amounts charged under the omnibus agreement are 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. We also incurred $8.0 million, $7.5 million and $4.5 million in public company expenses, excluding equity-based compensation, during the years ended December 31, 2010, 2009 and 2008, respectively. We did not incur public company expenses prior to our initial public offering in May 2008.

Term loan agreements and revolving credit agreement. From December 2008 to December 2010, we borrowed amounts under various term loans and our revolving credit facility primarily to finance various acquisitions. We have partially repaid amounts with proceeds from equity offerings as well as operating cash flows. As of December 31, 2010, our debt consists of (i) $250.0 million outstanding under our Wattenberg term loan, which bears interest at a variable rate based on London Interbank Offered Rate, or LIBOR, plus a margin ranging from 2.50% to 3.50%; (ii) $175.0 million outstanding under our term loan agreement with Anadarko, under which we pay interest at a fixed rate of 2.82%, reflecting an amendment to the term loan agreement made in December 2010; and (iii) $49.0 million outstanding under our revolving credit facility, under which we pay interest at LIBOR plus applicable margins ranging from 2.375% to 3.250%. See *Note 11 Debt and Interest Expense* included in the notes to the consolidated financial statements included under *Item 8* of this annual report.

Distributions. 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. We have made cash distributions to our unitholders since the third quarter of 2008 and have increased our quarterly distribution each quarter from the third quarter of 2009 through the fourth quarter of 2010. We did not pay cash distributions to our unitholders for quarterly periods prior to June 30, 2008. See *Note 4 Partnership Distributions* included in the notes to the consolidated financial statements included under *Item 8* of this annual report.

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. Prior to our acquisition of the Partnership Assets, except for Chipeta, we largely relied on internally generated cash flows and capital contributions from Anadarko to satisfy our capital expenditure requirements. In addition, all affiliate transactions related to such assets were net settled within our consolidated financial statements and were funded by Anadarko s working capital. Effective on the date of our acquisition of the Partnership Assets, except for Chipeta, all affiliate and third-party transactions related to such assets are funded by our working capital. Prior to June 1, 2008 (the date on which Anadarko initially contributed assets to Chipeta) 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. These factors impact the comparability of our cash flow statements, working capital analysis and liquidity.

Interest expense on intercompany balances. For periods prior to our acquisition of the Partnership Assets, except for Chipeta, we incurred interest expense or earned interest income on current intercompany balances with Anadarko related to such assets. These intercompany balances were extinguished through non-cash transactions in connection with the closing of our initial public offering, the Powder River acquisition, Anadarko s initial contribution of assets to Chipeta, the Granger acquisition, Wattenberg acquisition and AWC acquisition. Therefore, interest expense and interest income attributable to these balances is reflected in our historical consolidated financial statements for the periods ending prior to our acquisition of the Partnership Assets, except for Chipeta, and for periods ending prior to June 1, 2008 with respect to Chipeta.

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.

Equity-based compensation plans. In connection with the closing of our initial public offering, our general partner adopted two compensation plans: the LTIP and 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 and the general partner 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). 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. The equity-based compensation plans adopted in May 2008 impact the comparability of our financial statements for the year ended December 31, 2008 to subsequent periods.

GENERAL TRENDS AND OUTLOOK

We expect our business to continue to be affected by the following key trends. Our expectations are based on our assumptions 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 relatively low natural gas price environment, which has persisted over the past two years, has led to lower levels of drilling activity in dry-gas areas around certain of our assets. Several of our customers, including Anadarko, have reduced activity levels in dry-gas areas, shifting capital toward liquid-rich opportunities that offer higher margins and superior economics to producers. This trend has resulted in fewer new well connections in our dry-gas areas of operations and, in some cases, temporary curtailments of production in those areas. 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 the activities of natural gas producers and shippers.

Changes in regulations. Our operations and the operations of our customers have been, and at times in the future may be, affected by political developments and are subject to an increasing number of complex federal, state, tribal, local and other laws and regulations such as production restrictions, permitting delays, limitations on hydraulic fracturing and environmental protection regulations. We and/or our customers must obtain and maintain numerous permits, approvals and certificates from various federal, state, tribal and local governmental authorities. For example, regulation of hydraulic fracturing is currently primarily conducted at the state level through permitting and other compliance requirements. If proposed federal legislation is adopted, it could establish an additional level of regulation and permitting. Any changes in statutory regulations or delays in the issuance of required permits may impact both the throughput on and profitability of our systems.

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 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 inflation. Although inflation in the U.S. has been relatively low in recent years, the U.S. economy could experience a significant inflationary effect from, among other things, the governmental stimulus plans enacted since 2008. To the extent permitted by regulations and escalation provisions in our existing agreements, we have the ability to recover a portion of increased costs in the form of higher fees.

Impact of interest rates. Interest rates were at or near historic lows at certain times during 2010. Should interest rates rise, our financing costs would increase accordingly. Additionally, as with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and an associated implied distribution yield. 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 and our ability to issue additional equity, or increase the cost of issuing equity, to make acquisitions, reduce debt or for other purposes. However, we expect our cost of capital to remain competitive, as our competitors would face similar circumstances.

Acquisition opportunities. As of December 31, 2010, Anadarko s total domestic midstream asset portfolio, excluding the assets we own, consisted of eighteen gathering systems and nine processing and/or treating facilities, with an aggregate throughput of approximately 2.0 Bcf/d. A key component of our growth strategy is to acquire midstream assets from Anadarko and third parties over time. As of December 31, 2010, Anadarko owns a 2.0% general partner interest in us, all of our IDRs and a 46.5% 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 flows generated from operations on a per-unit basis.

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RESULTS OF OPERATIONS

OPERATING RESULTS

The following tables and discussion present a summary of our results of operations for the years ended December 31, 2010, 2009 and 2008:

	Year Ended December 31, 2010	2009	2008
	(in thousands)		
Revenues			
Gathering, processing and transportation of natural gas and natural gas liquids	**$ 231,829**	$ 226,399	$ 205,887
Natural gas, natural gas liquids and condensate sales	**258,820**	253,618	475,124
Equity income and other, net	**12,673**	10,529	17,757
Total revenues	**503,322**	490,546	698,768
Operating expenses (1)			
Cost of product	**157,049**	164,072	332,882
Operation and maintenance	**83,459**	89,535	92,126
General and administrative	**24,918**	28,452	23,330
Property and other taxes	**13,454**	13,566	13,398
Depreciation, amortization and impairments	**72,793**	66,784	71,040
Total operating expenses	**351,673**	362,409	532,776
Operating income	**151,649**	128,137	165,992
Interest income affiliates	**16,913**	17,536	12,148
Interest expense	**(18,794)**	(9,955)	(364)
Other income (expense), net	**(2,123)**	62	199
Income before income taxes	**147,645**	135,780	177,975
Income tax expense	**10,572**	17,614	43,747
Net income	**137,073**	118,166	134,228
Net income attributable to noncontrolling interests	**11,005**	10,260	7,908
Net income attributable to Western Gas Partners, LP	**$ 126,068**	**$** 107,906	$ 126,320
Key Performance Metrics (2)			
Gross margin	**$ 346,273**	$ 326,474	$ 365,886
Adjusted EBITDA	**$ 214,834**	$ 185,103	$ 229,926

Distributable cash flow	**$ 190,119**	$ 168,132	$ 201,250

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

(2) Gross margin, Adjusted EBITDA and distributable cash flow are defined under the caption *How We Evaluate Our Operations* 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.

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For purposes of the following discussion, any increases or decreases for the year ended December 31, 2010 refer to the comparison of the year ended December 31, 2010 to the year ended December 31, 2009, 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.

Operating Statistics

	Year Ended December 31,				
	2010	**2009**	**Δ[1]**	**2008**	**Δ[1]**
	(MMcf/d, except percentages and gross margin per Mcf)				
Gathering and transportation throughput [2]	**1,031**	1,145	(10)%	1,218	(6)%
Processing throughput [3]	**681**	637	7 %	524	22 %
Equity investment throughput [4]	**116**	120	(3)%	112	7 %
Total throughput	**1,828**	1,902	(4)%	1,854	3 %
Throughput attributable to noncontrolling interest owners	**197**	180	9 %	124	45 %
Total throughput attributable to Western Gas Partners, LP	**1,631**	1,722	(5)%	1,730	

(1) Represents the percentage change for the year ended December 31, 2010 or for the year ended December 31, 2009.

(2) Excludes NGL pipeline volumes measured in barrels.

(3) Includes 100% of Chipeta system volumes and 50% of Newcastle system volumes.

(4) Represents the Partnership s 14.81% share of Fort Union s gross volumes and excludes crude oil volumes measured in barrels attributable to the Partnership s interest in White Cliffs.

Gathering and transportation throughput decreased by 114 MMcf/d for the year ended December 31, 2010, primarily due to throughput decreases at the Pinnacle, Haley, Dew and Hugoton systems resulting from natural production declines and reduced drilling activity in those areas as a result of low natural gas prices. These declines were partially offset by throughput increases at the Wattenberg system due to increased drilling activity and recompletions driven by favorable producer economics in the area. Gathering and transportation throughput decreased by 73 MMcf/d for the year ended December 31, 2009, primarily comprised of throughput decreases at the Pinnacle, Dew and Hugoton systems due to natural production declines, partially offset by throughput increases at the Wattenberg system as a result of increased drilling activity and recompletions.

Processing throughput increased by 44 MMcf/d and 113 MMcf/d for the years ended December 31, 2010 and 2009, respectively. The increase for 2010 was attributable to increased throughput at the Chipeta system due to increased well connections driven by drilling activities in the Natural Buttes areas and at the Granger system resulting from the temporary redirection of volumes from competing systems during the last half of 2010. The increase for 2009 was primarily due to the completion of the cryogenic unit in April 2009 at the Chipeta system and increased throughput at the Granger system.

Equity investment volumes decreased slightly by 4 MMcf/d for the year ended December 31, 2010, due to reduced drilling activity around the Fort Union system and natural production declines. Equity investment volumes increased by 8 MMcf/d for the year ended December 31, 2009, primarily due to expansion of the Fort Union system.

Natural Gas Gathering, Processing and Transportation Revenues

	Year Ended December 31,				
	2010	**2009**	**Δ**	**2008**	**Δ**
	(in thousands, except percentages)				
Gathering, processing and transportation of natural gas and natural gas liquids	**$ 231,829**	$ 226,399	2%	$ 205,887	10%

Gathering, processing and transportation of natural gas and natural gas liquids revenues increased by $5.4 million for the year ended December 31, 2010 due to increased fee revenue at the Wattenberg and Granger systems. This increase resulted from changes in affiliate contract terms effective in July 2010 and October 2009, respectively, from primarily keep-whole and percentage-of-proceeds agreements to fee-based agreements. In addition, revenues increased due to higher rates at the Pinnacle, Hugoton and Wattenberg systems. These increases were partially offset by decreased throughput at the Pinnacle, Haley, Dew and Hugoton systems.

Gathering, processing and transportation of natural gas and natural gas liquids revenues increased by $20.5 million for the year ended December 31, 2009 primarily due to increased throughput at the Wattenberg and Chipeta systems and higher rates at the Haley and Wattenberg systems effective January 2009 and December 2008, respectively. These increases were partially offset by throughput decreases at the Pinnacle, Dew and Hugoton systems.

Natural Gas, Natural Gas Liquids and Condensate Sales

	Year Ended December 31,				
	2010	**2009**	**Δ**	**2008**	**Δ**
	(in thousands, except percentages and per-unit amounts)				
Natural gas sales	**$ 65,687**	$ 71,056	(8)%	$ 142,073	(50)%
Natural gas liquids sales	**167,975**	164,581	2%	297,529	(45)%
Drip condensate sales	**25,158**	17,981	40%	35,522	(49)%
Total	**$ 258,820**	$ 253,618	2%	$ 475,124	(47)%
Average price per unit:					
Natural gas (per Mcf)	**$ 5.83**	$ 4.11	42%	$ 7.03	(42)%
Natural gas liquids (per Bbl)	**$ 41.68**	$ 31.00	34%	$ 61.33	(49)%
Drip condensate (per Bbl)	**$ 70.50**	$ 47.87	47%	$ 84.62	(43)%

The average natural gas, NGL and condensate prices for the year ended December 31, 2010 include the effects of commodity price swap agreements attributable to sales for the Granger, Wattenberg, Hilight, Newcastle and Hugoton systems. The average natural gas and NGL prices for the year ended December 31, 2009 include the effects of commodity price swap agreements attributable to sales for only the Hilight and Newcastle systems. See *Note 6 Transactions with Affiliates Commodity price swap agreements* included in the notes to the consolidated financial statements included under *Item 8* of this annual report.

Total natural gas, natural gas liquids and condensate sales increased by $5.2 million for the year ended December 31, 2010, consisting of a $3.4 million and $7.2 million increase in NGLs sales and drip condensate sales, respectively, partially offset by a $5.4 million decrease in natural gas sales. The increase in NGLs sales is primarily attributable to improved liquids recoveries at the Chipeta system, and to a lesser extent, the 34% increase in NGL prices for 2010. This increase was partially offset by a 24% decrease in the volume of NGLs sold primarily due to the changes in affiliate contract terms at the Granger and Wattenberg systems effective in October 2009 and July 2010, respectively, allowing the producer to take its liquids and gas in-kind. The decrease in natural gas sales was due to a 42% decrease in the volume of natural gas sold primarily due to the changes in affiliate contract terms at the Granger and Wattenberg systems, as mentioned above. The decrease was partially offset by an increase in average natural gas sales prices. Natural gas and NGL prices pursuant to the commodity price swap agreements for the Granger system in 2010 were higher than 2009 market prices, and natural gas and NGL prices pursuant to the 2010 commodity price swap agreements for the Hilight and Newcastle systems were higher than 2009 commodity swap prices. The increase in drip condensate sales for the year ended December 31, 2010 was primarily due to a $22.63 per Bbl, or 47%, increase in the average price of condensate at the Hugoton and Wattenberg systems.

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Total natural gas, natural gas liquids and condensate sales decreased by $221.5 million for the year ended December 31, 2009, consisting of a $132.9 million, $71.0 million and $17.5 million decrease in NGLs sales, natural gas sales and drip condensate sales, respectively. The decrease in NGLs sales was primarily related to a 49% lower average NGLs price per barrel resulting from the decrease in market prices, partially offset by the fixed prices 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 decrease in NGLs sales attributable to pricing was partially offset by an approximate 508,000 Bbl increase in the volume of NGLs sold resulting from an increase in wellhead volumes delivered to the Granger system and improved NGL recoveries due to a change in the composition of the natural gas processed at the Granger system. In addition, volumes increased at the Chipeta and Wattenberg systems. These increases were partially offset by 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. For the year ended December 31, 2009, the decrease in natural gas sales was primarily due to lower sales volumes at the Granger and Wattenberg systems due to a $2.92 per Mcf, or 42%, decrease in the average price for natural gas sold and a 1.9 MMcf, or 10%, decrease in the volume of natural gas sold primarily at the Granger system due to improved NGL recoveries. The decrease in drip condensate sales for the year ended December 31, 2009 was primarily due to a $36.75 per Bbl, or 43%, decrease in average prices for drip condensate sold at the Hugoton and Wattenberg systems.

Equity Income and Other Revenues

	Year Ended December 31,				
	2010	**2009**	**Δ**	**2008**	**Δ**
	(in thousands, except percentages)				
Equity income	**$ 6,640**	$ 7,330	(9)%	$ 4,736	55%
Other revenues, net	**6,033**	3,199	89%	13,021	(75)%
Total equity income and other revenues, net	**$ 12,673**	$ 10,529	20%	$ 17,757	(41)%

Equity income decreased by $0.7 million for the year ended December 31, 2010 due to a decrease in Fort Union volumes resulting from natural production declines and our share of lower gains on interest rate swap agreements entered into by Fort Union. This decrease was partially offset by an increase in equity income attributable to White Cliffs resulting from the increase in ownership interest from 0.4% to 10.0% in September 2010 and the commencement of pipeline operations in June 2009.

Equity income increased by $2.6 million for the year ended December 31, 2009 primarily from the system expansion at Fort Union, our share of gains on interest rate swap agreements entered into by Fort Union, a $0.3 million gain recorded in connection with the reorganization of the majority owner of White Cliffs and the White Cliffs pipeline becoming operational in June 2009.

Other revenues, net increased by $2.8 million for the year ended December 31, 2010 primarily due to changes in gas imbalance positions at the Hilight, MIGC, Hugoton and Wattenberg systems and reimbursements from a third-party customer at the Pinnacle system for both installation costs and a shared equipment arrangement that ended in the third quarter of 2009.

Other revenues, net decreased by $9.8 million for the year ended December 31, 2009 due to changes in gas imbalance positions and related gas prices and $1.9 million of volume deficiency and indemnity payments received from two third parties during 2008.

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Cost of Product and Operation and Maintenance Expenses

	Year Ended December 31,				
	2010	**2009**	**Δ**	**2008**	**Δ**
	(in thousands, except percentages)				
Cost of product	**$ 157,049**	$ 164,072	(4)%	$ 332,882	(51)%
Operation and maintenance	**83,459**	89,535	(7)%	92,126	(3)%
Total cost of product and operation and maintenance expenses	**$ 240,508**	$ 253,607	(5)%	$ 425,008	(40)%

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. Cost of product expense for the years ended December 31, 2010 and 2009 also includes the effects of commodity price swap agreements attributable to certain purchases. See *Note 6 Transactions with Affiliates Commodity price swap agreements* of the notes to the consolidated financial statements included under *Item 8* of this annual report.

Cost of product expense decreased by $7.0 million for the year ended December 31, 2010 primarily consisting of a $9.0 million decrease in gathering fees paid by the Granger system for volumes gathered at adjacent gathering systems owned by Anadarko and a third party, then processed at Granger. Effective in October 2009, fees previously paid by Granger are now paid directly by the producer to the other gathering system owners. Cost of product expense also decreased $5.0 million due to a decrease in natural gas purchases, primarily due to lower volumes from the changes in affiliate contract terms at the Granger and Wattenberg systems effective in October 2009 and July 2010, respectively, and lower gas prices. In addition, cost of product expense decreased $1.1 million due to a decrease in the actual cost of fuel compared to the contractual cost of fuel, and decreased $0.6 million due to changes in gas imbalance positions. These decreases were offset by an $8.8 million increase in NGL purchases, primarily due to higher prices, offset by lower volumes from the changes in affiliate contract terms at the Granger and Wattenberg systems.

Cost of product expense decreased by $168.8 million for the year ended December 31, 2009. The decrease for the year ended December 31, 2009 includes a $162.5 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 net volumes, including the effects of commodity price swap agreements. In addition, cost of product expense decreased by $3.7 million 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, and decreased by $3.1 million due to a contract change at the Granger system related to volumes gathered at adjacent gathering systems owned by Anadarko and a third party, then processed at Granger as described above. Cost of product expense also decreased $2.7 million due to lower purchases resulting from the suspension of operations of the plant at the Hilight system in September 2008 and decreased $1.1 million due to a favorable change in the difference between actual versus contractual fuel recoveries. These decreases were slightly offset by a $4.3 million increase due to a change in imbalance positions and related gas prices.

Operation and maintenance expense decreased by $6.1 million for the year ended December 31, 2010 primarily due to lower compressor lease expenses resulting from the purchase of previously leased compressors used at the Granger and Wattenberg systems during 2010, lower electricity expense at the Chipeta system, lower chemical expenses and lower contract labor. The decreases in compressor lease expense for the year ended December 31, 2010 were offset by increases in depreciation expense discussed below under *General and Administrative, Depreciation and Other*

Expenses. In addition, the decrease in operating expense was partially offset by higher field personnel expenses, primarily attributable to merit increases.

Operation and maintenance expense decreased by $2.6 million for the year ended December 31, 2009 primarily due to a $2.8 million decrease in operating fuel costs attributable to the plant suspension at the Hilight system in September 2008 and a $1.4 million decrease in plant repair costs at the Granger system, partially offset by increases in costs related to employee incentive programs and an increase in operating expenses at the Chipeta plant associated with higher throughput following the completion of the cryogenic train in April 2009.

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General and Administrative, Depreciation, Impairments and Other Expenses

	Year Ended December 31,				
	2010	**2009**	**Δ**	**2008**	**Δ**
	(in thousands, except percentages)				
General and administrative	**$ 24,918**	$ 28,452	(12)%	$ 23,330	22%
Property and other taxes	**13,454**	13,566	(1)%	13,398	1%
Depreciation, amortization and impairments	**72,793**	66,784	9%	71,040	(6)%
Total general and administrative, depreciation and other expenses	**$ 111,165**	$ 108,802	2%	$ 107,768	1%

General and administrative expenses decreased by $3.5 million for the year ended December 31, 2010, due to the management fee allocated to the Granger assets and Wattenberg assets during the year ended December 31, 2009, then discontinued effective January 2010 and July 2010, respectively, upon contribution of the assets to us. This decrease was partially offset by an increase in corporate and management personnel costs allocated to us pursuant to the omnibus agreement. Depreciation, amortization and impairments increased by approximately $6.0 million for the year ended December 31, 2010 primarily attributable to capital projects completed at the Chipeta, Hilight and Hugoton systems as well as previously leased compressors used at the Granger and Wattenberg systems purchased and contributed to the Partnership during 2010.

General and administrative expenses increased by $5.1 million for the year ended December 31, 2009, primarily due to 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 incurred during 2009 attributable to acquisitions. Depreciation, amortization and impairments decreased by $4.3 million for the year ended December 31, 2009 primarily due to a $9.4 million impairment charge recognized in 2008 in connection with the plant suspension at the Hilight system prior to our acquisition of the Powder River assets, partially offset by higher depreciation attributable to assets placed in service during 2008 and 2009, including the Chipeta plant expansion completed in April 2009.

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Interest Income and Interest Expense

	Year Ended December 31,				
	2010	2009	Δ	2008	Δ
	(in thousands, except percentages)				
Interest income on note receivable	**$ 16,900**	$ 16,900	0 %	$ 10,703	58 %
Interest income, net on affiliate balances	**13**	636	(98)%	1,445	(56)%
Interest income affiliates	**$ 16,913**	$ 17,536	(4)%	$ 12,148	44 %
Third parties					
Interest expense on revolving credit facility and Wattenberg term loan	**$ (8,530)**	$ (304)	nm [1]	$	nm
Revolving credit facility fees and amortization	**(3,340)**	(555)	nm		nm
Affiliates					
Interest expense on notes payable	**(6,828)**	(8,953)	(24)%	(253)	nm
Credit facility commitment fees affiliates	**(96)**	(143)	(33)%	(111)	29 %
Interest expense	**$ (18,794)**	$ (9,955)	89 %	$ (364)	nm

(1) Percent change is not meaningful.

Interest income decreased by $0.6 million for the year ended December 31, 2010 due to the settlement of intercompany balances in connection with the Granger and Wattenberg acquisitions. Interest income increased by $5.4 million for the year ended December 31, 2009 due to interest income on our note receivable from Anadarko for the full year for 2009 compared to only seven and a half months for 2008.

Interest expense increased by $8.8 million for the year ended December 31, 2010, primarily due to interest expense incurred on the amounts outstanding during 2010 under the Wattenberg term loan, our revolving credit facility and related commitment fees. Interest expense increased by $9.6 million for the year ended December 31, 2009, due to interest expense on debt issued in connection with the Powder River acquisition in December 2008 and in connection with the Chipeta acquisition in July 2009.

See *Note 6 Transactions with Affiliates* and *Note 11 Debt and Interest Expense* included in the notes to the consolidated financial statements included under *Item 8* of this annual report.

Other Income (Expense), Net

	Year Ended December 31,				
	2010	2009	Δ	2008	Δ
	(in thousands, except percentages)				
Other income (expense), net	**$ (2,123)**	$ 62	nm[1]	$ 199	(69)%

(1) Percent change is not meaningful

Other income (expense), net for the year ended December 31, 2010 primarily consists of expense incurred in contemplation of refinancing existing borrowings under our revolving credit agreement with long-term fixed-rate notes. In April 2010, we entered into financial agreements to fix the underlying ten-year interest rates with respect to the potential note issuances. Upon reaching our decision not to issue the notes in May 2010, we terminated the agreements at a cost of $2.4 million.

Income Tax Expense

	Year Ended December 31,				
	2010	**2009**	**Δ**	**2008**	**Δ**
	(in thousands, except percentages)				
Income before income taxes	**$ 147,645**	$ 135,780	9%	$ 177,975	(24)%
Income tax expense	**10,572**	17,614	(40)%	43,747	(60)%
Effective tax rate	**7%**	13%		25%	

The Partnership is not a taxable entity for U.S. federal income tax purposes. Income earned by the Partnership prior to the closing date of our acquisition of the Partnership Assets, except for the Chipeta assets, was subject to federal and state income tax. Income earned by the Partnership including and subsequent to the closing date of our acquisition of the Partnership Assets, except for the Chipeta assets, was subject only to Texas margin tax on the portion of our income that was allocable to Texas. Substantially all of the income attributable to the Chipeta assets prior to the June 2008 formation of Chipeta was subject to federal and state income tax. Income earned by the Chipeta assets subsequent to June 2008 was subject only to Texas margin tax on the portion of income that was allocable to Texas.

Income tax expense decreased by $7.0 million and $26.1 million for the years ended December 31, 2010 and 2009, respectively. The decrease in income tax expense for the year ended December 31, 2010 is primarily a result of the income from the Granger and Wattenberg assets not being subject to federal or state income tax following their acquisition by the Partnership, except for the portion of such income that is allocable to Texas and subject to Texas margin tax. 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. Income tax also decreased for the year ended December 31, 2009 due to a decrease in income attributable to the Granger system and a decrease in Texas margin tax expense attributable to the initial assets. In addition, our estimated income earned by our initial assets and the Powder River assets allocable 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.

For 2010, 2009 and 2008, 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

	Year Ended December 31,				
	2010	**2009**	**Δ**	**2008**	**Δ**
	(in thousands, except percentages)				
Net income attributable to noncontrolling interests	**$ 11,005**	$ 10,260	7%	$ 7,908	30%

Net income attributable to noncontrolling interests increased by $0.7 million and $2.4 million for the years ended December 31, 2010 and 2009, respectively. Noncontrolling interests represent the aggregate 49% interest in Chipeta held by Anadarko and a third party. The increase in net income attributable to noncontrolling interests for the year ended December 31, 2010 is primarily due to higher throughput due to increased drilling activity in the Natural Buttes area. The increase in net 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.

Key Performance Metrics

	Year Ended December 31,				
	2010	**2009**	**Δ**	**2008**	**Δ**
	(in thousands, except percentages and gross margin per Mcf)				
Gross margin	**$ 346,273**	$ 326,474	6%	$ 365,886	(11)%
Gross margin per Mcf [1]	**0.52**	0.47	11%	0.54	(13)%
Gross margin per Mcf attributable to Western Gas Partners, LP [2]	**0.55**	0.49	12%	0.56	(13)%
Adjusted EBITDA [3]	**214,834**	185,103	16%	229,926	(19)%
Distributable cash flow [3]	**$ 190,119**	$ 168,132	13%	$ 201,250	(16)%

(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 the Partnership s 14.81% interest in income and volumes attributable to Fort Union.

(2) Calculated as gross margin, 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 attributable to the Partnership s investments in Fort Union and White Cliffs and volumes attributable to the Partnership s investment in Fort Union.

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

Gross margin. Gross margin increased by $19.8 million for the year ended December 31, 2010, primarily due to higher fee revenue at the Granger and Wattenberg systems resulting from the change in affiliate contract terms as well as higher throughput volumes at those systems. This increase is offset by lower throughput at the Pinnacle, Haley, Dew and Hugoton systems. Gross margin per Mcf increased by 11% and gross margin per Mcf attributable to Western Gas Partners, LP increased by 12% for the year ended December 31, 2010, primarily due to the changes in contract terms mentioned above and changes in the throughput mix within our portfolio.

Gross margin decreased by $39.4 million for the year ended December 31, 2009, primarily due to the decrease in natural gas and NGL prices, partially offset by a net increase in total 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. Gross margin per Mcf and gross margin per Mcf attributable to Western Gas Partners, LP decreased by 13% for the year ended December 31, 2009, primarily due to lower processing margins and lower drip condensate margins.

Adjusted EBITDA. Adjusted EBITDA increased by $29.7 million for the year ended December 31, 2010, primarily due to a $13.8 million increase in total revenues, excluding equity income; a $7.0 million decrease in cost of product; a $6.1 million decrease in operation and maintenance expenses; and a $4.0 million decrease in general and administrative expenses, excluding non-cash equity-based compensation and expenses in excess of the omnibus cap.

Adjusted EBITDA decreased by $44.8 million for the year ended December 31, 2009 primarily due to a $210.4 million decrease in total revenues excluding equity income, and a $2.6 million increase in general and administrative expenses, excluding non-cash equity-based compensation and expenses in excess of the omnibus cap, partially offset by a $168.8 million decrease in cost of product and a $2.6 million decrease in operation and maintenance expenses.

Distributable cash flow. Distributable cash flow increased by $22.0 million for the year ended December 31, 2010, primarily due to the $29.7 million increase in Adjusted EBITDA and a $1.6 million decrease in maintenance capital expenditures, partially offset by an $8.8 million increase in interest expense attributable to our borrowings related to the Granger acquisition and Wattenberg acquisition as well as revolving credit facility commitment fees.

Distributable cash flow decreased by $33.1 million for the year ended December 31, 2009, primarily due to the $44.8 million decrease in Adjusted EBITDA and a $9.6 million increase in interest expense on borrowings as well as revolving credit facility commitment fees, partially offset by a $15.1 million decrease in maintenance capital expenditures.

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LIQUIDITY AND CAPITAL RESOURCES

Our primary cash requirements are for acquisitions and other capital expenditures, debt service, customary operating expenses, quarterly distributions to our limited partners and general partner and distributions to our noncontrolling interest owners. Our sources of liquidity as of December 31, 2010 include cash flows generated from operations, including interest income on our $260.0 million note receivable from Anadarko; available borrowing capacity under our revolving credit facility; and issuances of additional common and general partner units. We believe that cash flows generated from the sources above 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 results of operations, financial conditions, capital requirements and other factors, and will be determined by the board of directors of our general partner on a quarterly basis. Due to our cash distribution policy, we expect to rely on external financing sources, including debt and common unit issuances, to fund expansion capital expenditures and future acquisitions. However, to limit interest expense, we may use operating cash flows to fund expansion capital expenditures or acquisitions, which could result in subsequent borrowing under our revolving credit facility to pay distributions or fund other short-term working capital requirements.

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. We have made cash distributions to our unitholders and have increased our quarterly distribution each quarter from the second quarter of 2009 through the fourth quarter of 2010. On January 19, 2011, the board of directors of our general partner declared a cash distribution to our unitholders of $0.38 per unit, or $30.6 million in aggregate, including incentive distributions. The cash distribution was paid on February 11, 2011 to unitholders of record at the close of business on February 1, 2011.

Management continuously monitors the Partnership s leverage position and coordinates its capital expenditure program, quarterly distributions and acquisition strategy with its expected cash flows and projected debt-repayment schedule. We will continue to evaluate funding alternatives, including additional borrowings and the issuance of debt or equity securities, to secure funds as needed or refinance outstanding debt balances with longer-term notes. To facilitate a potential debt or equity securities issuance, we have the ability to sell securities under our shelf registration statement, which became effective with the SEC in August 2009. Our ability to generate cash flows is subject to a number of factors, some of which are beyond our control. Please read *Item 1A Risk Factors* of this annual report.

Working capital. As of December 31, 2010 we had $1.0 million of working capital, which we define as the amount by which current assets exceed current liabilities. Working capital 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 and 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.

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

- maintenance capital expenditures, which include those expenditures required to maintain the existing operating capacity and service capability of our assets, such as to replace system components and equipment that have suffered significant use over time, become obsolete or approached the end of their useful lives, to remain in compliance with regulatory or legal requirements or to complete additional well connections to maintain existing system throughput 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 system throughput or capacity from current levels, including well connections that increase existing system throughput.

Capital expenditures in the consolidated statements of cash flows reflect capital expenditures on a cash basis, when payments are made. Capital incurred is presented on an accrual basis. Capital expenditures and capital incurred for the years ended December 31, 2010, 2009 and 2008, excluding amounts paid for acquisitions, were as follows:

	Year Ended December 31,		
	2010	2009	2008
	(in thousands)		
Expansion capital expenditures	**$ 54,475**	$ 50,479	$ 96,173
Maintenance capital expenditures	**22,359**	24,109	39,015
Total capital expenditures [(1)]	**$ 76,834**	$ 74,588	$ 135,188
Capital incurred [(2)]	**$ 79,484**	$ 62,704	$ 142,890

(1) Capital expenditures for the years ended December 31, 2010, 2009 and 2008 include $40.6 million, $36.3 million and $99.6 million, respectively, of pre-acquisition capital expenditures for the Partnership Assets and include the noncontrolling interest owners share of Chipeta s capital expenditures funded by contributions from the noncontrolling interest owners.

(2) Capital incurred for the years ended December 31, 2010, 2009 and 2008 includes $41.4 million, $42.0 million and $101.4 million, respectively, of pre-acquisition capital incurred for the Partnership Assets and include the noncontrolling interest owners share of Chipeta s capital expenditures funded by contributions from the noncontrolling interest owners.

Capital expenditures increased by $2.2 million for the year ended December 31, 2010. Excluding cash paid for acquisitions, expansion capital expenditures for the year ended December 31, 2010 increased by $4.0 million, primarily due to the purchase of previously leased compressors at the Granger and Wattenberg systems during 2010 prior to the Granger and Wattenberg acquisitions, offset by the completion of the cryogenic unit at the Chipeta plant and a compressor overhaul at the Hugoton system during 2009. In addition, maintenance capital expenditures decreased by $1.8 million, primarily as a result of fewer well connections.

Capital expenditures decreased by $60.6 million for the year ended December 31, 2009. Expansion capital expenditures decreased by $45.7 million, primarily due to capital expenditures during 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 compressor units at the Hugoton and Wattenberg systems during 2008, offset by the acquisition of the Natural Buttes plant during the fourth quarter of 2009. In addition, maintenance capital expenditures decreased by $14.9 million, primarily due to fewer well connections at the Haley, Hugoton, Pinnacle and Wattenberg systems as a result of reduced drilling activity and the completion of emission upgrades at the Wattenberg system during 2008. These decreases were 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 estimate our total capital expenditures for the year ending December 31, 2011, including our 51% share of Chipeta s capital expenditures and excluding acquisitions, to be $97 million to $112 million and our maintenance capital expenditures to be approximately 25% to 35% of total capital expenditures. Expected 2011 capital projects include expansion of the Platte Valley plant that we expect to acquire during the first quarter of 2011, our 51% share of the initial costs of a second cryogenic train at the Chipeta plant and expansion of the field compression and gathering pipelines around the Wattenberg and Hilight systems. See *Note 13 Subsequent Event* of the notes to the consolidated financial statements under *Item 8* of this annual report for a description of the Platte Valley acquisition. 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. 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, the issuance of additional partnership units or debt offerings.

Historical cash flows. The following table and discussion presents a summary of our net cash flows from operating activities, investing activities and financing activities as for the years ended December 31, 2010, 2009 and 2008.

	Year Ended December 31,		
	2010	**2009**	**2008**
	(in thousands)		
Net cash flows provided by (used in):			
Operating activities	**$ 217,074**	$ 164,870	$ 216,795
Investing activities	**(824,341)**	(176,421)	(578,283)
Financing activities	**564,357**	45,461	397,562
Net increase (decrease) in cash and cash equivalents	**$ (42,910)**	$ 33,910	$ 36,074

Operating activities. Net cash provided by operating activities increased by $52.2 million for the year ended December 31, 2010, primarily due to the following items:

- a $30.6 million increase due to changes in accounts payable balances and other items;
- a $13.8 million increase in revenues, excluding equity income;
- a $7.0 million decrease in cost of product expense;
- a $7.0 million decrease in income tax expense;
- a $6.1 million decrease in operating and maintenance expenses; and
- a $4.0 million decrease in general and administrative expenses, excluding non-cash equity-based compensation and expenses in excess of the omnibus cap.

The impact of the above items was partially offset by the following:

- an $8.8 million increase in interest expense settled in cash attributable to interest and fees on increased borrowings to partially fund the Granger acquisition and Wattenberg acquisition; and
- a $5.7 million decrease due to changes in accounts receivable balances.

Net cash provided by operating activities decreased by $51.9 million for the year ended December 31, 2009, primarily due to the following items:

- a $210.4 million decrease in revenues, excluding equity income;
- a $39.1 million decrease due to changes in accounts payable balances and other items;
- a $9.6 million increase in interest expense settled in cash attributable to interest and fees on increased borrowings to partially fund the Granger acquisition and Wattenberg acquisition; and

a $2.6 million increase in general and administrative expenses, excluding non-cash equity-based compensation and expenses in excess of the omnibus cap.

The impact of the above items was partially offset by the following:

a $168.8 million decrease in cost of product expense;

a $26.1 million decrease in income tax expense;

a $10.0 million increase due to changes in accounts receivable balances;

a $6.2 million increase in interest income on the note receivable from Anadarko issued in connection with our initial public offering; and

a $2.6 million decrease in operating and maintenance expenses.

Investing activities. Net cash used in investing activities for the year ended December 31, 2010 included payments of $473.1 million, $241.7 million and $38.0 million paid for the Wattenberg acquisition, Granger acquisition and White Cliffs acquisition, respectively, and $76.8 million of capital expenditures. See the sub-caption *Capital expenditures* above within this *Liquidity and Capital Resources* discussion. Net cash used in investing activities for 2010 from acquisitions and capital expenditures was offset by $5.2 million of proceeds from the sale of idle compressors to Anadarko and the sale of an idle refrigeration unit at the Granger system to a third party during 2010.

Net cash used in investing activities for the year ended December 31, 2009 included $101.5 million paid for the Chipeta acquisition in July 2009 and $74.6 million of capital expenditures.

Net cash used in investing activities for the year ended December 31, 2008 included the $260.0 million loan issued to Anadarko in connection with our May 2008 initial public offering and $175.0 million paid for the Powder River acquisition in December 2008. Net cash used in investing activities during 2008 also included $135.2 million of capital expenditures and $8.1 million of contributions to Fort Union in connection with the system expansion.

Financing activities. Net cash provided by financing activities for the year ended December 31, 2010 included the $450.0 million of borrowings to partially fund the Wattenberg acquisition, the $210.0 million in borrowings under our credit facility in connection with the Granger acquisition, $246.7 million of net proceeds from the November 2010 equity offering and $99.1 million of net proceeds from the May 2010 equity offering, offset by the $361.0 million of repayments of borrowings under our revolving credit facility. During 2010 we paid cash distributions to our unitholders of $94.2 million representing the $0.37 per-unit distribution for the quarter ended September 30, 2010, the $0.35 per-unit distribution for the quarter ended June 30, 2010, the $0.34 per-unit distribution for the quarter ended March 31, 2010 and the $0.33 per-unit distribution for the quarter ended December 31, 2009. Contributions from noncontrolling interest owners and Parent to Chipeta totaled $2.1 million during 2010. Distributions from Chipeta to noncontrolling interest owners totaled $13.2 million for 2010, representing the distribution of Chipeta s available cash. Net contributions from Parent were $24.9 million for 2010, representing the net settlement of January 2010 income taxes and certain other transactions attributable to the Granger assets and the net settlement of intercompany transactions attributable to the Wattenberg assets.

Net cash provided by financing activities for the year ended December 31, 2009 included $122.5 million of proceeds from the 2009 equity offering as well as the $101.5 million issuance of the three-year term loan to Anadarko in connection with the Chipeta acquisition, partially offset by its repayment in October 2009 and $4.3 million of costs paid in connection with the revolving credit facility we entered into in October 2009. The three-year term loan to Anadarko was repaid in October 2009 with $100.0 million of borrowings on our revolving credit facility and cash on hand, then such revolving credit facility borrowings were repaid in December 2009 with a portion of the net proceeds from our 2009 equity offering. For 2009, $70.1 million of cash distributions were paid to our unitholders, 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. Net distributions to Parent attributable to pre-acquisition intercompany balances were $35.0 million during 2009, representing the net non-cash settlement of intercompany transactions attributable to the Chipeta assets, Granger assets and Wattenberg assets. Financing proceeds for 2009 also included $40.3 million of contributions from noncontrolling interest owners and Parent attributable to the Chipeta plant construction, for which the associated capital expenditures are included in investing activities. Most of such 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 during 2009, representing the distribution of Chipeta s available cash.

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 2008 also included $175.0 million from the issuance of the five-year term loan to Anadarko in connection with the Powder River acquisition. Distributions to unitholders totaled $24.8 million during 2008, representing the $0.30 per-unit distributions the quarter ended September 30, 2008 and the $0.1582 per-unit distribution for the quarter ended June 30, 2008. Net distributions to Anadarko of $40.1 million for 2008, representing the net settlement of transactions attributable to the Powder River assets, Chipeta assets, Granger assets and Wattenberg assets. Financing proceeds for 2008 also included $55.4 million of 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. Distributions from Chipeta to noncontrolling interest owners and Parent totaled $37.9 million during 2008, including a $19.7 million one-time distribution to Anadarko following the initial formation of Chipeta.

Debt and credit facilities. As of December 31, 2010, our outstanding debt consisted of the $250.0 million term loan issued in connection with the Wattenberg acquisition, the $175.0 million note payable to Anadarko issued in connection with the Powder River acquisition and $49.0 million outstanding under our revolving credit facility. As of December 31, 2009, our outstanding debt consisted of the $175.0 million note payable to Anadarko. See *Note 11 Debt and Interest Expense* included in the notes to the consolidated financial statements under *Item 8* of this annual report.

Wattenberg term loan. In connection with the Wattenberg acquisition in August 2010, we borrowed $250.0 million under a three-year term loan from a group of banks (Wattenberg term loan). The Wattenberg term loan bears interest at LIBOR plus a margin, ranging from 2.50% to 3.50% depending on our consolidated leverage ratio, as defined in the Wattenberg term loan agreement. The Wattenberg term loan contains various customary covenants which are substantially similar to those in our revolving credit facility.

Note payable to Anadarko. In December 2008, we entered into a five-year $175.0 million term loan agreement with Anadarko in order to finance the cash portion of the consideration paid for the Powder River acquisition. The interest rate was fixed at 4.00% through November 2010, and is fixed at 2.82% thereafter, reflecting an amendment to the term loan agreement made in December 2010. The Partnership has the option to repay the outstanding principal amount in whole or in part.

The provisions of the five-year term loan agreement contain customary events of default, including (i) nonpayment of principal when due or nonpayment of interest or other amounts within three business days of when due, (ii) certain events of bankruptcy or insolvency with respect to the Partnership and (iii) a change of control.

Revolving credit facility. In October 2009, we entered into a three-year senior unsecured revolving credit facility. In January 2010, we borrowed $210.0 million under the revolving credit facility to partially fund the Granger acquisition. In May and June 2010, we repaid $100.0 million outstanding under the revolving credit facility using the proceeds from our May 2010 equity offering. In connection with the Wattenberg acquisition in August 2010, we exercised the accordion feature of our revolving credit facility, expanding the borrowing capacity from $350.0 million to $450.0 million, and borrowed $200.0 million under the facility. In November and December 2010, we repaid $261.0 million outstanding under the revolving credit facility using the proceeds from our November 2010 equity offering and operating cash flows. As of December 31, 2010, $49.0 million was outstanding under the revolving credit facility and $401.0 million was available for borrowing. We expect to have approximately $100.0 million of available borrowing capacity under our revolving credit facility after the closing of the Platte Valley acquisition. The revolving credit facility matures in October 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 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 our 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. The revolving credit facility also contains various customary covenants, customary events of default and certain financial tests, as of the end of each quarter, including a maximum consolidated leverage ratio (which is defined as the ratio of consolidated indebtedness as of the last day of a fiscal quarter to consolidated EBITDA for the most recent four consecutive fiscal quarters ending on such day) of 4.5 to 1.0, and a minimum consolidated interest coverage ratio (which is defined as the ratio of consolidated EBITDA for the most recent four consecutive fiscal quarters to consolidated interest expense for such period) of 3.0 to 1.0. 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., we will no longer be required to comply with the minimum consolidated interest coverage ratio as well as certain of the aforementioned covenants. As of December 31, 2010, we were in compliance with all covenants under the revolving credit facility.

Registered securities. As of December 31, 2010, we have the ability to issue up to approximately $771.2 million of limited partner common units and various debt securities under our effective shelf registration statement on file with the SEC.

Credit risk. We bear credit risk represented by our exposure to non-payment or non-performance by our counterparties, including Anadarko, financial institutions, customers and other parties. 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 third-party customers.

We are dependent upon a single producer, Anadarko, for the substantial 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, processing and transportation fees and for proceeds from the sale of residue gas, NGLs and condensate to Anadarko.

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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, which was issued concurrently with the closing of our initial public offering. We are also party to agreements 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 assets acquired from Anadarko. Finally, we have entered into various commodity price swap agreements with Anadarko in order to reduce our exposure to commodity price risk 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, contribution agreements or the commodity price swap agreements, as described in *Note 6 Transactions with Affiliates* included in the notes to the consolidated financial statements included under *Item 8* of this annual report, 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, 2010.

	Operating Leases	Environmental Obligations	Asset Retirement Obligations	Notes Payable Principal	Notes Payable Interest	Credit Facility Fees	Total
	(in thousands)						
2011	$ 362	$ 400	$	$	$ 14,810	$ 2,250	$ 17,822
2012	205	496		49,000	14,553	1,862	66,116
2013	188			425,000	9,986		435,174
2014	188						188
2015	188						188
Thereafter			40,197				40,197
Total	$ 1,131	$ 896	$ 40,197	$ 474,000	$ 39,349	$ 4,112	$ 559,685

Operating leases. Anadarko leases an office space and a warehouse used by us and charges rental payments to us. The amounts above represent the future minimum rent payments due under these operating leases.

Environmental obligations. We are subject to various environmental remediation obligations arising from federal, state and local laws and regulations. Management continually monitors the liability recorded and the remediation process and believes the amount recorded is appropriate. For additional information on environmental obligations, see *Note 12 Commitments and Contingencies Environmental obligations* of the notes to the consolidated financial statements under *Item 8* of this annual report.

Asset retirement obligations. When assets are acquired or constructed, the initial estimated asset retirement obligation is recognized in an amount equal to the net present value of the settlement obligation, with an associated increase in properties and equipment. Revisions to estimated asset retirement obligations can result from revisions to estimated inflation rates and discount rates, changes in retirement costs and 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.

Debt. For additional information on notes payable, see *Note 11 Debt and Interest Expense* of the notes to the consolidated financial statements under *Item 8* of this annual report.

Credit facility fees. We are required to pay facility fees on our $450.0 million revolving credit facility as described under the caption *Historical cash flows* above within this *Item 7*.

For additional information on contracts, obligations and arrangements the Partnership enters into from time to time, see *Note 6 Transactions with Affiliates*, *Note 12 Commitments and Contingencies* and *Note 13 Subsequent Event* of the notes to the consolidated financial statements under *Item 8* of this annual report.

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 22 years. If the depreciable lives of our assets were reduced by 10%, we estimate that annual depreciation expense would increase by approximately $8.5 million, which would result in a corresponding reduction in our operating income.

Impairments of tangible assets. Property, plant and equipment are generally stated at the lower of historical cost less accumulated depreciation or fair value, if impaired. Because acquisitions of assets from Anadarko are transfers of net assets between entities under common control, the Partnership Assets acquired by us from Anadarko are initially recorded at Anadarko s historic carrying value. Assets acquired in a business combination or non-monetary exchange with a third party are initially recorded at fair value. Property, plant and equipment balances are evaluated for potential impairment when events or changes in circumstances indicate that their carrying amounts 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 impairments, 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, processing and transporting the 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 impairments 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.

Impairments of goodwill. Goodwill represents the allocated portion of Anadarko s midstream goodwill attributed to the assets the Partnership has acquired from Anadarko. The carrying value of Anadarko s midstream goodwill represents the excess of the purchase price of an entity over the estimated fair value of the identifiable assets acquired and liabilities assumed by Anadarko. Accordingly, our goodwill balance does not reflect, and in some cases is significantly higher than, the difference between the consideration paid by us for acquisitions from Anadarko compared to the fair value of the net assets acquired. 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, 2010 was $55.4 million for the gathering and processing reporting unit and $4.8 million for the transportation reporting unit. 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.

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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 2011 Adjusted EBITDA. Management considered 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, throughput 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 and the initial recognition of environmental obligations assumed in third-party acquisitions. 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 multiple 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.

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

Commodity price risk. 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 New York Mercantile Exchange, or 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 this amount of gas by supplying additional gas or by paying an agreed-upon value for the gas utilized.

To mitigate our exposure to changes in commodity prices as a result of the purchase and sale of natural gas, condensate or NGLs, we entered into fixed-price commodity price swap agreements with Anadarko for the Powder River assets, which extend through December 31, 2012, with a Partnership option to extend through 2013; for the Granger assets, which extend through the end of 2014; for the Wattenberg assets, which extend through June 30, 2015; and for the Hugoton system, which extend through September 30, 2015. For additional information on the commodity price swap agreements, see *Note 6 Transactions with Affiliates* 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 existence of the commodity price swap agreements with Anadarko and the relatively small amount of our operating income that is impacted by changes in market prices. Accordingly, we do not expect a 10% change in natural gas or NGL prices to have a material direct impact on our operating income, financial condition or cash flows for the next twelve months, excluding the effect of natural gas imbalances described below.

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

Interest rate risk. Interest rates during 2009 and 2010 were low compared to historic rates. If interest rates rise, our future financing costs will increase. As of December 31, 2010, we owed $250.0 million under the Wattenberg term loan and $49.0 million under our revolving credit facility, both at variable interest rates based on LIBOR, and we owed $175.0 million under the note payable to Anadarko that bears a fixed rate. See *Note 11 Debt and Interest Expense* included in the notes to the consolidated financial statements included in *Item 8* of this annual report. For the year ended December 31, 2010, a 10% change in LIBOR would have resulted in a nominal change in net income.

We may incur additional debt in the future, either under the revolving credit facility or other financing sources, including commercial bank borrowings or debt issuances.

Item 8. *Financial Statements and Supplementary Data*

WESTERN GAS PARTNERS, LP

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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WESTERN GAS PARTNERS, LP

REPORT OF MANAGEMENT

Management of the Partnership s general partner prepared, and is responsible for, the consolidated financial statements and the other information appearing in this annual report. The consolidated financial statements present fairly the Partnership s financial position, results of operations and cash flows in conformity with accounting principles generally accepted in the United States. In preparing its consolidated financial statements, the Partnership includes amounts that are based on estimates and judgments that Management believes are reasonable under the circumstances. The Partnership s financial statements have been audited by KPMG LLP, an independent registered public accounting firm appointed by the Audit Committee of the Board of Directors. Management has made available to KPMG LLP all of the Partnership s financial records and related data, as well as the minutes of the Directors meetings.

MANAGEMENT S ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting. The Partnership s internal control system was designed to provide reasonable assurance to the Partnership s Management and Directors regarding the preparation and fair presentation of published financial statements.

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

Management assessed the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2010. This assessment was based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we believe that as of December 31, 2010 the Partnership s internal control over financial reporting is effective based on those criteria.

KPMG LLP has issued an attestation report on the Partnership s internal control over financial reporting as of December 31, 2010.

/s/ Donald R. Sinclair
Donald R. Sinclair
President and Chief Executive Officer
Western Gas Holdings, LLC
(as general partner of Western Gas Partners, LP)

/s/ Benjamin M. Fink
Benjamin M. Fink
Senior Vice President, Chief Financial Officer
and Treasurer
Western Gas Holdings, LLC
(as general partner of Western Gas Partners, LP)

February 24, 2011

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WESTERN GAS PARTNERS, LP

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Unitholders
Western Gas Holdings, LLC (as general partner of Western Gas Partners, LP):

We have audited Western Gas Partners, LP s (the Partnership) internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Western Gas Partners, LP s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management s Assessment of Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Partnership s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Western Gas Partners, LP maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Western Gas Partners, LP and subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of income, equity and partners capital, and cash flows for each of the years in the three-year period ended December 31, 2010, and our report dated February 24, 2011 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 24, 2011

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WESTERN GAS PARTNERS, LP

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Unitholders
Western Gas Holdings, LLC (as general partner of Western Gas Partners, LP):

We have audited the accompanying consolidated balance sheets of Western Gas Partners, LP (the Partnership) and subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of income, equity and partners capital, and cash flows for each of the years in the three-year period ended December 31, 2010. These consolidated financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Western Gas Partners, LP and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Western Gas Partners, LP s internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 24, 2011 expressed an unqualified opinion on the effectiveness of the Partnership s internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 24, 2011

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WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2010	2009	2008
	(in thousands, except per-unit data)		
Revenues affiliates			
Gathering, processing and transportation of natural gas and natural gas liquids	**$ 188,932**	$ 178,771	$ 157,969
Natural gas, natural gas liquids and condensate sales	**232,686**	222,828	396,449
Equity income and other	**8,451**	8,925	9,289
Total revenues affiliates	**430,069**	410,524	563,707
Revenues third parties			
Gathering, processing and transportation of natural gas and natural gas liquids	**42,897**	47,628	47,918
Natural gas, natural gas liquids and condensate sales	**26,134**	30,790	78,675
Other, net	**4,222**	1,604	8,468
Total revenues third parties	**73,253**	80,022	135,061
Total revenues	**503,322**	490,546	698,768
Operating expenses (1)			
Cost of product	**157,049**	164,072	332,882
Operation and maintenance	**83,459**	89,535	92,126
General and administrative	**24,918**	28,452	23,330
Property and other taxes	**13,454**	13,566	13,398
Depreciation, amortization and impairments	**72,793**	66,784	71,040
Total operating expenses	**351,673**	362,409	532,776
Operating income	**151,649**	128,137	165,992
Interest income affiliates	**16,913**	17,536	12,148
Interest expense (2)	**(18,794)**	(9,955)	(364)
Other income (expense), net	**(2,123)**	62	199
Income before income taxes	**147,645**	135,780	177,975
Income tax expense	**10,572**	17,614	43,747
Net income	**137,073**	118,166	134,228
Net income attributable to noncontrolling interests	**11,005**	10,260	7,908
Net income attributable to Western Gas Partners, LP	**$ 126,068**	**$** 107,906	**$** 126,320
Limited partner interest in net income:			
Net income attributable to Western Gas Partners, LP (3)	**$ 126,068**	$ 107,906	$ 126,320

Pre-acquisition net income allocated to Parent		**(11,937)**		(36,498)		(84,217)
General partner interest in net income		**(3,067)**		(1,428)		(842)
Limited partner interest in net income	**$**	**111,064**	$	69,980	$	41,261
Net income per common unit basic and diluted	**$**	**1.66**	$	1.25	$	0.78
Net income per subordinated unit basic and diluted	**$**	**1.61**	$	1.24	$	0.77
Net income per limited partner unit basic and diluted	**$**	**1.64**	$	1.24	$	0.78

(1) Operating expenses include amounts charged by Anadarko to the Partnership (Anadarko and Partnership are defined in *Note 1)* for services as well as reimbursement of amounts paid by Anadarko to third parties on behalf of the Partnership. Cost of product expenses include purchases from Anadarko of $63.4 million, $69.9 million and $134.3 million for the years ended December 31, 2010, 2009 and 2008, respectively. Operation and maintenance expenses include charges from Anadarko of $38.1 million, $35.3 million and $34.3 million for the years ended December 31, 2010, 2009 and 2008, respectively. General and administrative expenses include charges from Anadarko of $19.1 million, $22.7 million and $20.0 million for the years ended December 31, 2010, 2009 and 2008, respectively. See *Note 6.*

(2) Interest expense includes affiliate interest expense of $6.9 million, $9.1 million and $0.4 million for the years ended December 31, 2010, 2009 and 2008, respectively. See *Note 11.*

(3) General and limited partner interest in net income represents net income for periods including and subsequent to the Partnership s acquisition of the Partnership Assets (as defined in *Note 1*). See also *Note 5.*

See accompanying notes to the consolidated financial statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2010	December 31, 2009
	(in thousands, except number of units)	
ASSETS		
Current assets		
Cash and cash equivalents	$ **27,074**	$ 69,984
Accounts receivable, net third parties	**9,140**	9,200
Accounts receivable, net affiliates	**1,750**	2,203
Natural gas imbalance receivables third parties	**95**	266
Natural gas imbalance receivables affiliates	**11**	448
Other current assets	**5,114**	4,163
Total current assets	**43,184**	86,264
Long-term assets		
Note receivable Anadarko	**260,000**	260,000
Plant, property and equipment		
Cost	**1,727,231**	1,660,297
Less accumulated depreciation	**367,881**	299,309
Net property, plant and equipment	**1,359,350**	1,360,988
Goodwill	**60,236**	57,348
Equity investments	**40,406**	21,344
Other assets	**2,361**	2,974
Total assets	$ **1,765,537**	$ 1,788,918
LIABILITIES, EQUITY AND PARTNERS CAPITAL		
Current liabilities		
Accounts and natural gas imbalance payables third parties	$ **13,695**	$ 15,627
Accounts and natural gas imbalance payables affiliate	**1,480**	1,319
Accrued ad valorem taxes	**5,986**	6,319
Income taxes payable	**160**	412
Accrued liabilities third parties	**20,280**	11,010
Accrued liabilities affiliates	**593**	470
Total current liabilities	**42,194**	35,157
Long-term liabilities		
Long-term debt third parties	**299,000**	
Note payable Anadarko	**175,000**	175,000
Deferred income taxes	**733**	217,312
Asset retirement obligations and other	**43,542**	55,976
Total long-term liabilities	**518,275**	448,288

Total liabilities	**560,469**	483,445
Commitments and contingencies (Note 12)		
Equity and partners capital		
Common units (51,036,968 and 36,374,925 units issued and outstanding at December 31, 2010 and 2009, respectively)	**810,717**	497,230
Subordinated units (26,536,306 units issued and outstanding at December 31, 2010 and 2009)	**282,384**	276,571
General partner units (1,583,128 and 1,283,903 units issued and outstanding at December 31, 2010 and 2009, respectively)	**21,505**	13,726
Parent net investment		427,024
Total partners capital	**1,114,606**	1,214,551
Noncontrolling interests	**90,462**	90,922
Total equity and partners capital	**1,205,068**	1,305,473
Total liabilities, equity and partners capital	**$ 1,765,537**	$ 1,788,918

See accompanying notes to the consolidated financial statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENTS OF EQUITY AND PARTNERS CAPITAL

		Partners Capital				
	Parent Net	Limited Partners		General	Noncontrolling	
	Investment	Common	Subordinated	Partner	Interests	Total
	(in thousands)					
Balance at December 31, 2007	$ 912,596	$	$	$	$ (92)	912,504
Net pre-acquisition distributions to Parent	(145,103)					(145,103)
Elimination of net deferred tax liabilities	126,936					126,936
Contribution of initial assets	(321,609)	55,221	255,941	10,447		
Acquisition of Powder River assets	(160,851)	(13,866)		(283)		(175,000)
Contribution of other assets from Parent	2,089	2,528	11,715	478		16,810
Reimbursement to Parent from offering proceeds	(45,161)					(45,161)
Issuance of common units to public, net of offering and other costs		315,161				315,161
Non-cash equity-based compensation		324				324
Net income	84,217	20,841	20,420	842	7,908	134,228
Contributions from noncontrolling interest owners and Parent	88,465				73,105	161,570
Distributions to noncontrolling interest owners and Parent	(22,668)				(15,201)	(37,869)
Distributions to unitholders		(12,159)	(12,159)	(496)		(24,814)
Other	(296)				296	
Balance at December 31, 2008	$ 518,615	$ 368,050	$ 275,917	$ 10,988	$ 66,016	$ 1,239,586
Net pre-acquisition distributions to Parent	(35,317)					(35,317)
Acquisition of Chipeta assets	(112,744)	11,068		225		(101,451)
Issuance of common and general partner units, net of offering costs		120,080		2,459		122,539
		366				366

Non-cash equity-based compensation						
Net income	36,498	37,035	32,945	1,428	10,260	118,166
Contributions from noncontrolling interest owners and Parent	20,544				19,718	40,262
Distributions to noncontrolling interest owners and Parent	(2,926)				(5,072)	(7,998)
Distributions to unitholders		(36,025)	(32,640)	(1,401)		(70,066)
Other	2,354	(3,344)	349	27		(614)
Balance at December 31, 2009	$ 427,024	$ 497,230	$ 276,571	$ 13,726	$ 90,922	$ 1,305,473
Net contributions from Parent	**29,843**					**29,843**
Acquisition of Granger assets	**(300,367)**	**57,513**		**1,174**		**(241,680)**
Acquisition of Wattenberg assets	**(382,848)**	**(88,447)**		**(1,805)**		**(473,100)**
Acquisition of White Cliffs from affiliate	**(1,272)**	**(18,728)**				**(20,000)**
Contribution of other assets from Parent		**10,500**		**215**		**10,715**
Issuance of common and general partner units, net of offering costs		**338,483**		**7,320**		**345,803**
Non-cash equity-based compensation		**302**				**302**
Elimination of net deferred tax liabilities	**214,464**					**214,464**
Net income	**11,937**	**68,410**	**42,654**	**3,067**	**11,005**	**137,073**
Contributions from noncontrolling interest owners and Parent					**2,053**	**2,053**
Distributions to noncontrolling interest owners and Parent					**(13,222)**	**(13,222)**
Distributions to unitholders		**(55,108)**	**(36,885)**	**(2,201)**		**(94,194)**
Other	**1,219**	**562**	**44**	**9**	**(296)**	**1,538**
Balance at December 31, 2010	**$**	**$ 810,717**	**$ 282,384**	**$ 21,505**	**$ 90,462**	**$ 1,205,068**

See accompanying notes to the consolidated financial statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2010	2009	2008
	(in thousands)		
Cash flows from operating activities			
Net income	**$ 137,073**	$ 118,166	$ 134,228
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization and impairments	**72,793**	66,784	71,040
Deferred income taxes	**(1,650)**	(4,063)	(1,603)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable, net	**(269)**	1,795	(160)
(Increase) decrease in natural gas imbalance receivables	**608**	4,292	(3,728)
Increase (decrease) in accounts and natural gas imbalance payables and accrued liabilities	**10,936**	(20,071)	18,383
Change in other items, net	**(2,417)**	(2,033)	(1,365)
Net cash provided by operating activities	**217,074**	164,870	216,795
Cash flows from investing activities			
Capital expenditures	**(76,834)**	(74,588)	(135,188)
Acquisitions from affiliates	**(734,780)**	(101,451)	(175,000)
Acquisition from third parties	**(18,047)**		
Investments in equity affiliates	**(310)**	(382)	(8,095)
Loan to Anadarko			(260,000)
Proceeds from sale of assets to third party	**2,825**		
Proceeds from sale of assets to affiliate	**2,805**		
Net cash used in investing activities	**(824,341)**	(176,421)	(578,283)
Cash flows from financing activities			
Proceeds from issuance of common and general partner units, net of $14.7 million, $5.5 million and $28.2 million in offering and other expenses for the years ended December 31, 2010, 2009 and 2008, respectively	**345,803**	122,539	315,161
Borrowings on revolving credit facility, net of issuance cost	**409,988**		
Issuance of Wattenberg term loan	**250,000**		
Issuance of notes payable to Anadarko		101,451	175,000
Repayment of note payable to Anadarko		(101,451)	
Repayments of revolving credit facility	**(361,000)**		
Revolving credit facility issuance costs		(4,263)	
Reimbursement to Parent from offering proceeds			(45,161)
Distributions to unitholders	**(94,194)**	(70,066)	(24,814)
Net contributions from (distributions to) Anadarko	**24,929**	(35,013)	(40,117)
Contributions from noncontrolling interest owners and Parent	**2,053**	40,262	55,362
Distributions to noncontrolling interest owners and Parent	**(13,222)**	(7,998)	(37,869)

Net cash provided by financing activities	**564,357**	45,461	397,562
Net (decrease) increase in cash and cash equivalents	**(42,910)**	33,910	36,074
Cash and cash equivalents at beginning of period	**69,984**	36,074	
Cash and cash equivalents at end of period	**$ 27,074**	$ 69,984	$ 36,074
Supplemental disclosures			
Significant non-cash investing and financing transactions:			
Contribution of initial assets from Parent	**$**	$	$ 321,609
Elimination of net deferred tax liabilities	**$ 214,464**	$	$ 126,936
Property, plant and equipment and other assets contributed by Parent	**$ 7,598**	$	$ 123,018
Increase (decrease) in accrued capital expenditures	**$ 2,652**	$ (13,148)	$ 9,228
Interest paid	**$ 16,497**	$ 9,372	$ 82
Interest received	**$ 16,900**	$ 16,900	$ 7,887
Taxes paid	**$ 507**	$	$

See accompanying notes to the consolidated financial statements.

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WESTERN GAS PARTNERS, LP
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1. DESCRIPTION OF BUSINESS AND BASIS OF PRESENTATION

Basis of presentation. Western Gas Partners, LP (the Partnership) is a Delaware limited partnership formed in August 2007. As of December 31, 2010, the Partnership s assets included ten gathering systems, six natural gas treating facilities, six natural gas processing facilities, one natural gas liquids (NGL) pipeline, one interstate pipeline and a noncontrolling interest in Fort Union Gas Gathering, L.L.C. (Fort Union) and White Cliffs Pipeline, L.L.C. (White Cliffs). The Partnership s assets are located in East and West Texas, the Rocky Mountains (Colorado, Utah and Wyoming) and the Mid-Continent (Kansas and Oklahoma). The Partnership is engaged in the business of gathering, processing, compressing, treating and transporting natural gas, NGLs and crude oil for Anadarko Petroleum Corporation and its consolidated subsidiaries and third-party producers and customers. For purposes of these financial statements, the Partnership refers to Western Gas Partners, LP and its subsidiaries; Anadarko or Parent refers to Anadarko Petroleum Corporation and its consolidated subsidiaries, excluding the Partnership and the general partner; and affiliates refers to wholly owned and partially owned subsidiaries of Anadarko, excluding the Partnership, and also refers to Fort Union and White Cliffs. The Partnership s general partner is Western Gas Holdings, LLC, a wholly owned subsidiary of Anadarko.

The accompanying consolidated financial statements of the Partnership have been prepared in accordance with the U.S. Generally Accepted Accounting Principles (GAAP). The consolidated financial statements include the accounts of the Partnership and entities in which it holds a controlling financial interest. All significant intercompany transactions have been eliminated. Investments in non-controlled entities over which the Partnership exercises significant influence are accounted for under the equity method. The Partnership records its 50% proportionate share of the assets, liabilities, revenues and expenses attributed to the Newcastle system.

Acquisitions. Since its inception, the Partnership has completed the following acquisitions:

Initial assets acquisition. Concurrent with the closing of the initial public offering (described below under *Equity offerings*), Anadarko contributed the assets and liabilities of Anadarko Gathering Company LLC (AGC), Pinnacle Gas Treating LLC (PGT) and MIGC LLC (MIGC) to the Partnership in exchange for 1,083,115 general partner units, representing a 2.0% general partner interest in the Partnership, 100% of the incentive distribution rights (IDRs), 5,725,431 common units and 26,536,306 subordinated units. AGC, PGT and MIGC are referred to collectively as the initial assets. The common units issued to Anadarko in exchange for their contribution of the initial assets include 751,625 common units issued representing the portion of the common units for which the underwriters did not exercise their over-allotment option. See *Note 4 Partnership Distributions* for information related to the distribution rights of the common and subordinated unitholders and to the IDRs held by the general partner.

Powder River acquisition. In December 2008, the Partnership acquired certain midstream assets from Anadarko for consideration consisting of (i) $175.0 million in cash, which was financed by borrowing $175.0 million from Anadarko pursuant to the terms of a five-year term loan agreement, and (ii) the issuance of 2,556,891 common units and 52,181 general partner units. The acquisition consisted of (i) a 100% ownership interest in the Hilight system, (ii) a 50% interest in the Newcastle system and (iii) a 14.81% limited liability company membership interest in Fort Union. These assets are referred to collectively as the Powder River assets and the acquisition is referred to as the Powder River acquisition.

Chipeta acquisition. In July 2009, the Partnership acquired certain midstream assets from Anadarko for (i) approximately $101.5 million in cash, which was financed by borrowing $101.5 million from Anadarko pursuant to the terms of a 7.0% fixed-rate, three-year term loan agreement, and (ii) the issuance of 351,424 common units and

7,172 general partner units. These assets provide processing and transportation services in the Greater Natural Buttes area in Uintah County, Utah. The acquisition consisted of a 51% membership interest in Chipeta Processing LLC (Chipeta), together with an associated NGL pipeline. Chipeta owns a natural gas processing plant complex, which includes two processing trains: a refrigeration unit completed in November 2007 and a cryogenic unit which was completed in April 2009. The 51% membership interest in Chipeta and associated NGL pipeline are referred to collectively as the Chipeta assets and the acquisition is referred to as the Chipeta acquisition.

Natural Buttes Plant acquisition. In November 2009, Chipeta closed its acquisition of a compressor station and processing plant (the Natural Buttes plant) from a third party for $9.1 million. The noncontrolling interest owners contributed $4.5 million to Chipeta during the year ended December 31, 2009 to fund their proportionate share of the Natural Buttes plant acquisition. The Natural Buttes plant is located in Uintah County, Utah.

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Granger acquisition. In January 2010, the Partnership acquired certain midstream assets from Anadarko for (i) approximately $241.7 million in cash, which was financed primarily with a $210.0 million draw on the Partnership s revolving credit facility plus cash on hand, and (ii) the issuance of 620,689 common units and 12,667 general partner units. The assets acquired represent Anadarko s entire 100% ownership interest in the following assets located in Southwestern Wyoming: (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. These assets are referred to collectively as the Granger assets and the acquisition is referred to as the Granger acquisition. In September 2010, the Partnership sold an idle refrigeration train at the Granger system to a third party for $2.4 million.

Wattenberg acquisition. In August 2010, the Partnership acquired certain midstream assets from Anadarko for (i) $473.1 million in cash, which was funded with $250.0 million of borrowings under a bank-syndicated unsecured term loan, $200.0 million of borrowings under the Partnership s revolving credit facility and $23.1 million of cash on hand; as well as (ii) the issuance of 1,048,196 common units and 21,392 general partner units. The assets acquired represent a 100% ownership interest in Kerr-McGee Gathering LLC, which owns the Wattenberg gathering system and related facilities, including the Fort Lupton processing plant. These assets, located in the Denver-Julesburg Basin, north and east of Denver, Colorado, are referred to collectively as the Wattenberg assets and the acquisition as the Wattenberg acquisition.

White Cliffs acquisition. In September 2010, the Partnership and Anadarko closed a series of related transactions through which the Partnership acquired a 10% member interest in White Cliffs. Specifically, the Partnership acquired Anadarko s 100% ownership interest in Anadarko Wattenberg Company, LLC (AWC) for $20.0 million in cash (the AWC acquisition). AWC owned a 0.4% interest in White Cliffs and held an option to increase its interest in White Cliffs. Also, in a series of concurrent transactions, AWC acquired an additional 9.6% interest in White Cliffs from a third party for $18.0 million in cash, subject to post-closing adjustments. White Cliffs owns a crude oil pipeline that originates in Platteville, Colorado and terminates in Cushing, Oklahoma and became operational in June 2009. The Partnership s acquisition of the 0.4% interest in White Cliffs and related purchase option from Anadarko and the acquisition of an additional 9.6% interest in White Cliffs were funded with cash on hand and are referred to collectively as the White Cliffs acquisition. The Partnership s interest in White Cliffs is referred to as the White Cliffs investment.

Platte Valley acquisition agreement. In January 2011, the Partnership entered into an agreement to acquire the Platte Valley gathering system and processing plant from a third party. See *Note 13 Subsequent Event* for additional information.

Presentation of Partnership acquisitions. References to Partnership Assets refer collectively to the initial assets, Powder River assets, Chipeta assets, Natural Buttes plant, Granger assets, Wattenberg assets and the White Cliffs investment. Unless otherwise noted, references to periods prior to our acquisition of the Partnership Assets and similar phrases refer to periods prior to May 2008 with respect to the initial assets, periods prior to December 2008 with respect to the Powder River assets, periods prior to July 2009 with respect to the Chipeta assets, periods prior to November 2009 with respect to the Natural Buttes plant, periods prior to January 2010 with respect to the Granger assets, periods prior to July 2010 with respect to the Wattenberg assets and periods prior to September 2010 with respect to the White Cliffs investment. References to periods including and subsequent to our acquisition of the Partnership Assets and similar phrases refer to periods including and subsequent to May 2008 with respect to the initial assets, periods including and subsequent to December 2008 with respect to the Powder River assets, periods including and subsequent to July 2009 with respect to the Chipeta assets, periods subsequent to November 2009 with respect to the Natural Buttes plant, periods including and subsequent to January 2010 with respect to the Granger assets, periods including and subsequent to July 2010 with respect to the Wattenberg assets, and periods including and subsequent to September 2010 with respect to the White Cliffs investment.

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Anadarko acquired MIGC, the Powder River assets and the Granger assets in connection with its August 23, 2006 acquisition of Western Gas Resources, Inc. (Western) and Anadarko acquired the Chipeta assets and the Wattenberg assets in connection with its August 10, 2006 acquisition of Kerr-McGee Corporation (Kerr-McGee). In addition, Anadarko made its initial investment in White Cliffs on January 29, 2007. Because of Anadarko s control of the Partnership through its ownership of the general partner, each acquisition of Partnership Assets, except for the Natural Buttes plant and the acquisition of a 9.6% interest in White Cliffs, was considered a transfer of net assets between entities under common control. As a result, after each acquisition of assets from Anadarko, the Partnership is required to revise its financial statements to include the activities of the Partnership Assets as of the date of common control. Accordingly, the Partnership s consolidated financial statements include (i) the combined financial results and operations of AGC and PGT from their inception through the closing date of the Partnership s initial public offering and (ii) the consolidated financial results and operations of Western Gas Partners, LP and its subsidiaries from the closing date of the Partnership s initial public offering thereafter, combined with (a) the financial results and operations of MIGC, the Powder River assets and Granger assets, from August 23, 2006 thereafter, (b) the financial results and operations of the Chipeta assets and Wattenberg assets, from August 10, 2006 thereafter, and (c) the 0.4% interest in White Cliffs from January 29, 2007 thereafter. Net income attributable to the Partnership Assets for periods prior to the Partnership s acquisition of such assets is not allocated to the limited partners for purposes of calculating net income per limited partner unit.

The consolidated financial statements for periods prior to the Partnership s acquisition of the Partnership Assets have been prepared from Anadarko s historical cost-basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if the Partnership had owned the assets and operated as a separate entity during the periods reported. In addition, certain amounts in prior periods have been reclassified to conform to the current presentation.

Equity offerings. Since its inception, the Partnership has completed the following public equity offerings:

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

2009 equity offering. In December 2009, the Partnership closed its equity offering of 6,900,000 common units to the public at a price of $18.20 per unit, including the issuance of 900,000 units to the public pursuant to the full exercise of the underwriters over-allotment option granted in connection with the equity offering. The December 2009 issuances are referred to 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 the Partnership s revolving credit facility and to partially fund the January 2010 Granger acquisition referenced above. In connection with the 2009 equity offering, the Partnership issued 140,817 general partner units to the general partner.

May 2010 equity offering. In May and June 2010, the Partnership closed its equity offering of 4,558,700 common units to the public at a price of $22.25 per unit, including the issuance of 558,700 common units to the public pursuant to the exercise of the underwriters over-allotment option granted in connection with the equity offering. The May and June 2010 issuances are referred to collectively as the May 2010 equity offering. In connection with the May 2010 equity offering, the Partnership issued 93,035 general partner units to Anadarko. Net proceeds from the offering of approximately $99.1 million, including the general partner s proportionate capital contribution to maintain its 2.0%

interest, and cash on hand were used to repay $100.0 million outstanding under the Partnership s revolving credit facility.

November 2010 equity offering. In November 2010, the Partnership closed a public offering of 8,415,000 common units at a price of $29.92 per unit, including the issuance of 915,000 common units to the public pursuant to the partial exercise of the underwriters over-allotment option granted in connection with that offering. The November 2010 issuances are referred to collectively as the November 2010 equity offering. The net proceeds included $5.1 million from Anadarko in exchange for 171,734 general partner units, representing the general partner s proportionate capital contribution to maintain its 2.0% interest. Net proceeds from the offering of approximately $246.7 million were used to repay $246.0 million outstanding under the Partnership s revolving credit facility.

WESTERN GAS PARTNERS, LP
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Limited partner and general partner units. The following table summarizes common, subordinated and general partner units issued during the years ended December 31, 2010, 2009 and 2008 (in thousands):

	Limited Partner Units		General	
	Common	Subordinated	Partner Units	Total
Initial public offering and contribution of initial public assets	26,536	26,536	1,083	54,155
Powder River acquisition	2,557		52	2,609
Balance at December 31, 2008	29,093	26,536	1,135	56,764
Chipeta acquisition	352		7	359
2009 equity offering	6,900		141	7,041
Long-Term Incentive Plan awards	30		1	31
Balance at December 31, 2009	36,375	26,536	1,284	64,195
Granger acquisition	**621**		**12**	**633**
Long-Term Incentive Plan awards	**19**		**1**	**20**
May 2010 equity offering	**4,559**		**93**	**4,652**
Wattenberg acquisition	**1,048**		**21**	**1,069**
November 2010 equity offering	**8,415**		**172**	**8,587**
Balance at December 31, 2010	**51,037**	**26,536**	**1,583**	**79,156**

Anadarko holdings of Partnership Equity. As of December 31, 2010, Anadarko held 1,583,128 general partner units representing a 2% general partner interest in the Partnership, 100% of the Partnership s IDRs, 10,302,631 common units and 26,536,306 subordinated units. Anadarko owned an aggregate 46.5% limited partner interest in the Partnership based on its holdings of common and subordinated units. The public held 40,734,337 common units, representing a 51.5% limited partner interest in the Partnership.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of estimates. To conform to accounting principles generally accepted in the U.S., management makes estimates and assumptions that affect the amounts reported in the consolidated financial statements and the notes thereto. These estimates are evaluated on an ongoing basis, utilizing historical experience and other methods considered reasonable in the particular circumstances. Although these estimates are based on management s best available knowledge at the time, actual results may differ.

Effects on the Partnership s business, financial condition and results of operations resulting from revisions to estimates are recognized when the facts that give rise to the revision become known. Changes in facts and circumstances or discovery of new facts or circumstances may result in revised estimates and actual results may differ from these estimates.

Fair value. The fair-value-measurement standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The standard characterizes inputs used in determining fair value according to a hierarchy that prioritizes those inputs based upon the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

Level 1 inputs represent quoted prices in active markets for identical assets or liabilities.

Level 2 inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).

Level 3 inputs that are not observable from objective sources, such as management s internally developed assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in management s internally developed present value of future cash flows model that underlies the fair value measurement).

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Nonfinancial assets and liabilities initially measured at fair value include certain assets and liabilities acquired in a third-party business combination, assets and liabilities exchanged in non-monetary transactions, impaired long-lived assets (asset groups), impaired goodwill, initial recognition of asset retirement obligations and initial recognition of environmental obligations assumed in a third-party acquisition. Impairment analyses for long-lived assets and goodwill, and the initial recognition of asset retirement obligations and environmental obligations use Level 3 inputs.

The fair value of the note receivable from Anadarko reflects any premium or discount for the differential between the stated interest rate and quarter-end market rate, based on quoted market prices of similar debt instruments. See *Note 6 Transactions with Affiliates* for disclosures regarding the fair value of the note receivable from Anadarko.

The fair value of debt is the estimated amount the Partnership would have to pay to repurchase its debt, including any premium or discount attributable to the difference between the stated interest rate and market rate of interest at the balance sheet date. Fair values are based on quoted market prices or average valuations of similar debt instruments at the balance sheet date for those debt instruments for which quoted market prices are not available. See *Note 11 Debt and Interest Expense* for disclosures regarding the fair value of debt.

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable reported on the consolidated balance sheets approximate fair value due to the short-term nature of these items.

Cash equivalents. The Partnership considers all highly liquid investments with an original maturity date of three months or less to be cash equivalents. The Partnership had approximately $27.1 million and $70.0 million of cash and cash equivalents as of December 31, 2010 and December 31, 2009, respectively.

Bad-debt reserve. The Partnership revenues are primarily from Anadarko, for which no credit limit is maintained. The Partnership analyzes its exposure to bad debt on a customer-by-customer basis for its third-party accounts receivable and may establish credit limits for significant third-party customers. For third-party accounts receivable, the amount of bad-debt reserve at December 31, 2010 and 2009 was approximately $17,000 and $114,000, respectively.

Natural gas imbalances. The consolidated balance sheets include natural gas imbalance receivables and payables resulting from differences in gas volumes received into the Partnership s systems and gas volumes delivered by the Partnership to customers. Natural gas volumes owed to or by the Partnership that are subject to monthly cash settlement are valued according to the terms of the contract as of the balance sheet dates, and reflect market index prices. Other natural gas volumes owed to or by the Partnership are valued at the Partnership s weighted average cost of natural gas as of the balance sheet dates and are settled in-kind. As of December 31, 2010, natural gas imbalance receivables and payables were approximately $0.1 million and $2.6 million, respectively. As of December 31, 2009, natural gas imbalance receivables and payables were approximately $0.7 million and $1.8 million, respectively. Changes in natural gas imbalances are reported in equity income and other revenues or cost of product expense in the consolidated statements of income.

Inventory. The cost of natural gas and NGLs inventories are determined by the weighted average cost method on a location-by-location basis. Inventory is accounted for at the lower of weighted average cost or market value and is reported in other current assets in the consolidated balance sheets.

Property, plant and equipment. Property, plant and equipment are generally stated at the lower of historical cost less accumulated depreciation or fair value, if impaired. Because acquisitions of assets from Anadarko are transfers of net assets between entities under common control, the Partnership Assets acquired by the Partnership from Anadarko are initially recorded at Anadarko s historic carrying value. The difference between the carrying value of net assets acquired from Anadarko and the consideration paid is recorded as an adjustment to Partners capital. Further, assets acquired in a business combination or non-monetary exchange with a third party are initially recorded at fair value. The Partnership capitalizes all construction-related direct labor and material costs. The cost of renewals and betterments that extend the useful life of property, plant and equipment is also capitalized. The cost of repairs, replacements and major maintenance projects that do not extend the useful life or increase the expected output of property, plant and equipment is expensed as incurred.

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Depreciation is computed over the asset s estimated useful life using the straight-line method or half-year convention method, based on estimated useful lives and salvage values of assets. Uncertainties that may impact these estimates include, but are not limited to changes in laws and regulations relating to environmental matters, including air and water quality, restoration and abandonment requirements, economic conditions and supply and demand in the area. When assets are placed into service, the Partnership makes estimates with respect to useful lives and salvage values that the Partnership believes are reasonable. However, subsequent events could cause a change in estimates, thereby impacting future depreciation amounts.

The Partnership evaluates its ability to recover the carrying amount of its long-lived assets and determines whether its long-lived assets have been impaired. Impairments exist when the carrying amount of an asset exceeds estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, estimates of future undiscounted cash flows take into account possible outcomes and probabilities of their occurrence. If the carrying amount of the long-lived asset is not recoverable, based on the estimated future undiscounted cash flows, the impairment loss is measured as the excess of the asset s carrying amount over its estimated fair value, such that the asset s carrying amount is adjusted to its estimated fair value with an offsetting charge to operating expense.

Fair value represents the estimated price between market participants to sell an asset in the principal or most advantageous market for the asset, based on assumptions a market participant would make. When warranted, management assesses the fair value of long-lived assets using commonly accepted techniques and may use more than one source in making such assessments. Sources used to determine fair value include, but are not limited to, recent third-party comparable sales, internally developed discounted cash flow analyses and analyses from outside advisors. Significant changes, such as changes in contract rates or terms, the condition of an asset, or management s intent to utilize the asset generally require management to reassess the cash flows related to long-lived assets.

Capitalized Interest. Interest is capitalized as part of the historical cost of constructing assets for significant projects. Significant construction projects that are in progress qualify for interest capitalization. Capitalized interest is determined by multiplying the Partnership s weighted-average borrowing cost on debt by the average amount of qualifying costs incurred. Once an asset subject to interest capitalization is completed and placed in service, the associated capitalized interest is expensed through depreciation or impairment, along with other capitalized costs related to that asset.

Goodwill. Goodwill as of December 31, 2010 and 2009 represents the allocated portion of Anadarko s midstream goodwill attributed to the assets the Partnership has acquired from Anadarko. The carrying value of Anadarko s midstream goodwill represents the excess of the purchase price of an entity over the estimated fair value of the identifiable assets acquired and liabilities assumed by Anadarko. Accordingly, the Partnership s goodwill balance does not reflect, and in some cases is significantly higher than, the difference between the consideration the Partnership paid for its acquisitions from Anadarko and the fair value of the net assets on the acquisition date. During 2010, the carrying amount of goodwill increased by $2.9 million, to $60.2 million, attributable to a revision in the amount of goodwill allocated to the Granger acquisition. During 2009, the carrying amount of goodwill did not change.

The Partnership evaluates whether goodwill has been impaired. Impairment testing is performed annually as of October 1, unless facts and circumstances make it necessary to test more frequently. The Partnership has determined that it has one operating segment and two reporting units: (i) gathering and processing and (ii) transportation. 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. No goodwill impairment has been recognized in these consolidated financial statements. A reduction of the carrying value of goodwill would represent a Level 3 fair value measure.

WESTERN GAS PARTNERS, LP
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Equity-method investments. The Partnership s investments in Fort Union and White Cliffs are accounted for under the equity method of accounting. Fort Union is a joint venture among Copano Pipelines/Rocky Mountains, LLC (37.04%), Crestone Powder River L.L.C. (37.04%), Bargath, Inc. (11.11%) and the Partnership (14.81%). Fort Union owns a gathering pipeline and treating facilities in the Powder River Basin. Anadarko is the construction manager and physical operator of the Fort Union facilities. Certain business decisions, including, but not limited to, decisions with respect to significant expenditures or contractual commitments, annual budgets, material financings, dispositions of assets or amending the owners firm gathering agreements, require 65% or unanimous approval of the owners.

In September 2010, the Partnership completed the White Cliffs acquisition. See *Note 1 Description of Business and Basis of Presentation Acquisitions*. White Cliffs owns a crude oil pipeline that originates in Platteville, Colorado and terminates in Cushing, Oklahoma and became operational in June 2009. White Cliffs is a limited liability company owned by SemCrude Pipeline L.P. (51.0%), Plains Pipeline L.P. (34.0%), Noble Energy, Inc. (5.0%) and the Partnership (10.0%). The third-party majority owner is the manager of the White Cliffs operations. Certain business decisions, including, but not limited to, approval of annual budgets and decisions with respect to significant expenditures, contractual commitments, acquisitions, material financings, dispositions of assets or admitting new members, require more than 75% approval of the members.

Management evaluates its equity-method investments for impairment whenever events or changes in circumstances indicate that the carrying value of such investment may have experienced a decline in value that is other than temporary. When evidence of loss in value has occurred, management compares the estimated fair value of the investment to the carrying value of the investment to determine whether the investment has been impaired. Management assesses the fair value of equity-method investments using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third-party comparable sales and discounted cash flow models. If the estimated fair value is less than the carrying value, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.

The equity investment balance at December 31, 2010 includes $21.0 million and $19.0 million for the investments in Fort Union and White Cliffs, respectively. The equity investment balance at December 31, 2009 includes $20.1 million and $1.2 million for the investments in Fort Union and White Cliffs, respectively. The investment balance at December 31, 2010 includes $2.8 million for the purchase price allocated to the investment in Fort Union in excess of Western s historic cost basis. This balance was attributed to the difference between the fair value and book value of Fort Union s gathering and treating facilities and is being amortized over the remaining life of those facilities. The carrying value of the Partnership s investment in Fort Union approximates the Partnership s underlying equity in Fort Union s net assets as of December 31, 2010. The White Cliffs investment balance at December 31, 2010 is approximately $11.3 million less than the Partnership s underlying equity in White Cliffs net assets as of December 31, 2010, primarily due to the Partnership recording the acquisition of its initial 0.4% interest in White Cliffs at Anadarko s historic carrying value. This difference will be amortized to equity income over the remaining estimated useful life of the White Cliffs pipeline. Investment earnings from Fort Union and White Cliffs, net of amortization, were $6.6 million, $7.3 million and $4.7 million for the years ended December 31, 2010, 2009 and 2008, respectively, and are reported in equity income and other within revenues affiliates in the consolidated statements of income. Distributions from Fort Union and White Cliffs totaled $5.9 million, $5.6 million and $5.1 million for the years ended December 31, 2010, 2009 and 2008, respectively.

At December 31, 2010, Fort Union had expansion projects under construction and had project financing debt of $86.0 million outstanding, which is not guaranteed by the members. Fort Union s lender has a lien on the Partnership s interest in Fort Union.

Asset retirement obligations. Management recognizes a liability based on the estimated costs of retiring tangible long-lived assets. The liability is recognized at fair value, measured using discounted expected future cash outflows for the asset retirement obligation when the obligation originates, which generally is when an asset is acquired or constructed. The carrying amount of the associated asset is increased commensurate with the liability recognized. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. Subsequent to the initial recognition, the liability is also adjusted for any changes in the expected value of the retirement obligation (with a corresponding adjustment to property, plant and equipment) until the obligation is settled. Revisions in estimated asset retirement obligations may result from changes in estimated inflation rates, discount rates, retirement costs and the estimated timing of settling asset retirement obligations. See *Note 10 Asset Retirement Obligations*.

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Environmental expenditures. The Partnership expenses environmental expenditures related to conditions caused by past operations that do not generate current or future revenues. Environmental expenditures related to operations that generate current or future revenues are expensed or capitalized, as appropriate. Liabilities are recorded when the necessity for environmental remediation or other potential environmental liabilities becomes probable and the costs can be reasonably estimated. Accruals for estimated losses from environmental remediation obligations are recognized no later than at the time of the completion of the remediation feasibility study. These accruals are adjusted as additional information becomes available or as circumstances change. Costs of future expenditures for environmental-remediation obligations are not discounted to their present value. See *Note 12 Commitments and Contingencies Environmental obligations*.

Segments. The Partnership s operations are organized into a single operating segment, the assets of which consist of natural gas, NGLs and crude oil gathering and processing systems, treating facilities, pipelines and related plants and equipment.

Revenues and cost of product. Under its fee-based arrangements, the Partnership is paid a fixed fee based on the volume and thermal content of the natural gas it gathers or treats, and recognizes gathering and treating revenues for its services in the month such services are performed. Producers wells are connected to the Partnership s gathering systems for delivery of natural gas to the Partnership s processing or treating plants, where the natural gas is processed to extract NGLs and condensate or treated in order to satisfy pipeline specifications. In some areas, where no processing is required, the producers gas is gathered, and delivered to pipelines for market delivery.

Under percent-of-proceeds contracts, revenue is recognized when the natural gas, NGLs or condensate are sold and the related purchases are recorded as a percentage of the product sale.

The Partnership purchases natural gas volumes at the wellhead for gathering and processing. As a result, the Partnership has volumes of NGLs and condensate to sell and volumes of residue gas to either sell, use for system fuel or to satisfy keep-whole obligations. In addition, depending upon specific contract terms, condensate and NGLs recovered during gathering and processing are either returned to the producer, or retained and sold. Under keep-whole contracts, when condensate or NGLs are retained and sold, producers are kept whole for the condensate or NGL volumes through the receipt of a thermally equivalent volume of residue gas. The keep-whole contract conveys an economic benefit to the Partnership when the individual values of the NGLs are greater as liquids than as a component of the natural gas stream; however, the Partnership is adversely impacted when the value of the NGLs are lower as liquids than as a component of the natural gas stream. Revenue is recognized from the sale of condensate and NGLs upon transfer of title and related purchases are recorded as cost of product.

Except for volumes taken in-kind by certain producers or sold to third parties, an affiliate of Anadarko sells the natural gas and extracted NGLs. During 2009, agreements were entered into with an affiliate of Anadarko whereby the affiliate purchases certain NGLs from the Wattenberg assets, then sells such volumes to third parties. Previously, NGLs from the Wattenberg assets were retained by the system and sold directly to third parties.

The Partnership earns transportation revenues through firm contracts that obligate each of its customers to pay a monthly reservation or demand charge regardless of the pipeline capacity used by that customer. An additional commodity usage fee is charged to the customer based on the actual volume of natural gas transported. Revenues are also generated from interruptible contracts pursuant to which a fee is charged to the customer based on volumes transported through the pipeline. Revenues for transportation of natural gas and NGLs are recognized over the period of firm transportation contracts or, in the case of usage fees and interruptible contracts, when the volumes are received into the pipeline. From time to time, certain revenues may be subject to refund pending the outcome of rate matters before the Federal Energy Regulatory Commission and reserves are established where appropriate. During the periods presented herein, there were no pending rate cases and no related reserves have been established.

Proceeds from the sale of residue gas, NGLs and condensate are reported as revenues from natural gas, natural gas liquids and condensate in the consolidated statements of income. Revenues attributable to the fixed-fee component of gathering and processing contracts as well as demand charges and commodity usage fees on transportation contracts are reported as revenues from gathering, processing and transportation of natural gas and natural gas liquids in the consolidated statements of income.

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Equity-based compensation. Concurrent with the closing of the initial public offering, phantom unit awards were granted to independent directors of the general partner under the Western Gas Partners, LP 2008 Long-Term Incentive Plan (LTIP), which permits the issuance of up to 2,250,000 units. The general partner awarded additional phantom units primarily to the general partner s independent directors under the LTIP in May 2010 and 2009. Upon vesting of each phantom unit, the holder will receive common units of the Partnership or, at the discretion of the general partner s board of directors, cash in an amount equal to the market value of common units of the Partnership on the vesting date. Equity-based compensation expense attributable to grants made under the LTIP will impact the Partnership s 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. The Partnership amortizes stock-based compensation expense attributable to awards granted under the LTIP over the vesting periods applicable to the awards.

Additionally, the Partnership s general and administrative expenses include equity-based compensation costs allocated by Anadarko to the Partnership for grants made pursuant to the Western Gas Holdings, LLC Equity Incentive Plan as amended and restated (Incentive Plan) as well as the Anadarko Petroleum Corporation 1999 Stock Incentive Plan and the Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan (Anadarko s plans are referred to collectively as the Anadarko Incentive Plans). Under the Incentive Plan, participants are granted Unit Value Rights (UVRs), Unit Appreciation Rights (UARs) and Dividend Equivalent Rights (DERs). UVRs and UARs granted under the Incentive Plan (i) were collectively valued at approximately $215.00 per unit and $67.00 per unit as of December 31, 2010 and 2009, respectively. The UVRs and UARs either vest ratably over three years or vest in two equal installments on the second and fourth anniversaries of the grant date, or earlier in connection with certain other events. Upon the occurrence of a UVR vesting event, each participant will receive a lump-sum cash payment (net of any applicable withholding taxes) for each UVR. The UVRs may not be sold or transferred except to the general partner, Anadarko or any of its affiliates. After the occurrence of a UAR vesting event, each participant will receive a lump-sum cash payment (net of any applicable withholding taxes) for each UAR that is exercised prior to the earlier of the 90th day after a participant s voluntary termination and the 10th anniversary of the grant date. DERs granted under the Incentive Plan vest upon the occurrence of certain events, become payable no later than 30 days subsequent to vesting and expire 10 years from the date of grant. Grants made under equity-based compensation plans result in equity-based compensation expense, which is determined by reference to the fair value of equity compensation. For equity-based awards ultimately settled through the issuance of units or stock, the fair value is as of the date of the relevant equity grant. For equity-based awards issued under the Incentive Plan and ultimately settled in cash, the initial fair value as of the date of the relevant equity grant is revised periodically based on the estimated fair value of the Partnership s general partner using a discounted cash flow estimate and multiples-valuation terminal value (Level 3 fair value measures). Equity-based compensation expense attributable to grants made under the Incentive Plan will impact the Partnership s cash flows 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 the Partnership s cash flows from operating activities. See *Note 6 Transactions with Affiliates.*

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Income taxes. The Partnership generally is not subject to federal income tax or state income tax other than Texas margin tax on the portion of our income that is allocable to Texas. Federal and state income tax expense was recorded prior to the Partnership s acquisition of the Partnership Assets, except for the Chipeta assets. In addition, deferred federal and state income taxes are recorded on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases with respect to the Partnership Assets prior to the Partnership s acquisition; and deferred state income taxes are recorded with respect to the Partnership Assets including and subsequent to our acquisition, except for the Chipeta assets. The recognition of deferred federal and state tax assets prior to the Partnership s acquisition of the Partnership Assets was based on management s belief that it was more likely than not that the results of future operations would generate sufficient taxable income to realize the deferred tax assets. For periods including or subsequent to the Partnership s acquisition of the Partnership Assets, the Partnership is only subject to Texas margin tax; therefore, deferred federal income tax assets and liabilities with respect to the Partnership Assets for periods including and subsequent to the Partnership s acquisitions are no longer recognized by the Partnership. Substantially all of the income attributable to the Chipeta assets prior to the June 2008 formation of Chipeta, at which time substantially all of the Chipeta assets were contributed to a non-taxable entity for U.S. federal income tax purposes, was subject to federal and state income taxes, while income earned by the Chipeta assets subsequent to June 2008 was subject only to Texas margin tax.

For periods including and subsequent to the Partnership s acquisition of the Partnership Assets, the Partnership makes payments to Anadarko pursuant to the tax sharing agreement entered into between Anadarko and the Partnership for its estimated share of non-U.S. federal taxes that are included in any combined or consolidated returns filed by Anadarko. The aggregate difference in the basis of the Partnership s Assets for financial and tax reporting purposes cannot be readily determined as the Partnership does not have access to information about each partner s tax attributes in the Partnership.

The accounting standard for uncertain tax positions defines the criteria an individual tax position must meet for any part of the benefit of that position to be recognized in the financial statements. The Partnership has no material uncertain tax positions at December 31, 2010 or 2009.

Net income per limited partner unit. Certain accounting standards address the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and undistributed earnings of the entity when, and if, it declares dividends on its securities. The accounting standards require securities that satisfy the definition of a participating security to be considered for inclusion in the computation of basic earnings per unit using the two-class method. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed pursuant to the terms of the relevant contractual arrangement. For the Partnership, earnings per unit is calculated based on the assumption that the Partnership distributes to its unitholders an amount of cash equal to the net income of the Partnership, notwithstanding the general partner s ultimate discretion over the amount of cash to be distributed for the period, the existence of other legal or contractual limitations that would prevent distributions of all of the net income for the period or any other economic or practical limitation on the ability to make a full distribution of all of the net income for the period. The Partnership applies the two-class method in determining net income per unit applicable to master limited partnerships having multiple classes of securities including limited partnership units, general partnership units and IDRs of the general partner. The accounting guidance provides the methodology for and circumstances under which undistributed earnings are allocated to the general partner, limited partners and IDR holders.

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The Partnership s net income 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, and when applicable, giving effect to incentive distributions allocable to the general partner. The Partnership s net income allocable to the limited partners is allocated between the common and subordinated unitholders by applying the provisions of the partnership agreement that govern actual cash distributions as if all earnings for the period had been distributed. Specifically, net income equal to the amount of available cash (as defined by the partnership agreement) is allocated to the general partner, common unitholders and subordinated unitholders consistent with actual cash distributions, including incentive distributions allocable to the general partner. Undistributed earnings (net income in excess of distributions) or undistributed losses (available cash in excess of net income) are then allocated to the general partner, common unitholders and subordinated unitholders in accordance with their respective ownership percentages during each period. See *Note 5 Net Income per Limited Partner Unit*.

3. NONCONTROLLING INTERESTS

In July 2009, the Partnership acquired a 51% interest in Chipeta. Chipeta is a Delaware limited liability company formed in April 2008 to construct and operate a natural gas processing facility. As of December 31, 2010, Chipeta is owned 51% by the Partnership, 24% by Anadarko and 25% by a third-party member. The interests in Chipeta held by Anadarko and the third-party member are reflected as noncontrolling interests in the consolidated financial statements for all periods presented.

In connection with the Partnership s acquisition of its 51% membership interest in Chipeta, the Partnership became party to Chipeta s limited liability company agreement, as amended and restated as of July 23, 2009 (the Chipeta LLC agreement), together with Anadarko and the third-party member. The Chipeta LLC agreement provides the following:

- Chipeta s members will be required from time to time to make capital contributions to Chipeta to the extent approved by the members in connection with Chipeta s annual budget;
- Chipeta will distribute available cash, as defined in the Chipeta LLC agreement, if any, to its members quarterly in accordance with those members membership interests; and
- Chipeta s membership interests are subject to significant restrictions on transfer.

Upon acquisition of its interest in Chipeta, the Partnership became the managing member of Chipeta. As managing member, the Partnership manages the day-to-day operations of Chipeta and receives a management fee from the other members, which is intended to compensate the managing member for the performance of its duties. The Partnership may only be removed as the managing member if it is grossly negligent or fraudulent, breaches its primary duties or fails to respond in a commercially reasonable manner to written business proposals from the other members, and such behavior, breach or failure has a material adverse effect to Chipeta.

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4. PARTNERSHIP DISTRIBUTIONS

The partnership agreement requires that, within 45 days subsequent to the end of each quarter, beginning with the quarter ended June 30, 2008, the Partnership distribute all of its available cash (as defined in the partnership agreement) to unitholders of record on the applicable record date. The Partnership declared the following cash distributions to its unitholders for the years ended December 31, 2010, 2009 and 2008 (in thousands, except per-unit data):

Quarters Ended	Total Quarterly Distribution per Unit	Total Cash Distribution	Date of Distribution
2008			
June 30 (1)	$ 0.1582	$ 8,567	August 2008
September 30	$ 0.30	$ 16,247	November 2008
December 31	$ 0.30	$ 17,029	February 2009
2009			
March 31	$ 0.30	$ 17,030	May 2009
June 30	$ 0.31	$ 17,718	August 2009
September 30	$ 0.32	$ 18,289	November 2009
December 31	$ 0.33	$ 21,393	February 2010
2010			
March 31	**$ 0.34**	**$ 22,042**	**May 2010**
June 30	**$ 0.35**	**$ 24,378**	**August 2010**
September 30	**$ 0.37**	**$ 26,381**	**November 2010**
December 31 (2)	**$ 0.38**	**$ 30,564**	**February 2011**

(1) Represents a quarterly distribution of $0.30 per unit for the 48-day period beginning on the closing date of the Partnership s initial public offering and ending on June 30, 2008.

(2) On January 19, 2011, the board of directors of the Partnership s general partner declared a cash distribution to the Partnership s unitholders of $0.38 per unit, or $30.6 million in aggregate, including incentive distributions. The cash distribution was paid on February 11, 2011 to unitholders of record at the close of business on February 1, 2011.

Available cash. The amount of available cash (as defined in the partnership agreement) generally is all cash on hand at the end of the quarter, plus, at the discretion of the general partner, working capital borrowings made subsequent to the end of such quarter, less the amount of cash reserves established by the Partnership s general partner to provide for the proper conduct of the Partnership s business, including reserves to fund future capital expenditures, to comply with applicable laws, debt instruments or other agreements, or to provide funds for distributions to its unitholders and to its general partner for any one or more of the next four quarters. Working capital borrowings generally include borrowings made under a credit facility or similar financing arrangement. It is intended that working capital borrowings be repaid within 12 months. In all cases, working capital borrowings are used solely for working capital purposes or to fund distributions to partners.

Minimum quarterly distributions. The partnership agreement provides that, during a period of time referred to as the subordination period, the common units are entitled to distributions of available cash each quarter in an amount equal to the minimum quarterly distribution, which is $0.30 per common unit, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash are permitted on the subordinated units. Furthermore, arrearages do not apply to and 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. From its inception through December 31, 2010, the Partnership has paid equal distributions on common, subordinated and general partner units and there are no distributions in arrears on common units.

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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, the Partnership s general partner is entitled to incentive distributions if the amount the Partnership distributes with respect to any quarter exceeds specified target levels shown below:

	Total Quarterly Distribution Target Amount	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum quarterly distribution	$0.30	98 %	2 %
First target distribution	up to $0.345	98 %	2 %
Second target distribution	above $0.345 up to $0.375	85 %	15 %
Third target distribution	above $0.375 up to $0.450	75 %	25 %
Thereafter	above $0.45	50 %	50 %

The table above assumes that the Partnership s general partner maintains its 2.0% general partner interest, that there are no arrearages on common units and the general partner continues to own the IDRs. The maximum distribution sharing percentage of 50.0% includes distributions paid to the general partner on its 2.0% general partner interest and does not include any distributions that the general partner may receive on limited partner units that it owns or may acquire.

5. NET INCOME PER LIMITED PARTNER UNIT

Basic and diluted net income per limited partner unit is calculated by dividing the limited partners interest in net income by the weighted average number of limited partner units outstanding during the period. The number of units issued in connection with the initial public offering, including shares issued in connection with the partial exercise of the underwriters over-allotment option, is used for purposes of calculating basic earnings per unit for 2008 as if the shares were outstanding from May 14, 2008, the closing date of the initial public offering. The common units and general partner units issued in connection with acquisitions and equity offerings during 2009 and 2010 are included on a weighted-average basis for periods they were outstanding.

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The following table illustrates the Partnership s calculation of net income per unit for common and subordinated limited partner units (in thousands, except per-unit information):

	Year Ended December 31, 2010	2009	2008
Net income attributable to Western Gas Partners, LP	**$ 126,068**	$ 107,906	$ 126,320
Pre-acquisition net income allocated to Parent	**(11,937)**	(36,498)	(84,217)
General partner interest in net income	**(3,067)**	(1,428)	(842)
Limited partner interest in net income	**$ 111,064**	$ 69,980	$ 41,261
Net income allocable to common units	**$ 68,410**	**$** 37,035	**$** 20,841
Net income allocable to subordinated units	**42,654**	32,945	20,420
Limited partner interest in net income	**$ 111,064**	$ 69,980	$ 41,261
Net income per limited partner unit basic and diluted			
Common units	**$ 1.66**	$ 1.25	$ 0.78
Subordinated units	**$ 1.61**	$ 1.24	$ 0.77
Total limited partner units	**$ 1.64**	$ 1.24	$ 0.78
Weighted average limited partner units outstanding basic and diluted			
Common units	**41,287**	29,684	26,680
Subordinated units	**26,536**	26,536	26,536
Total limited partner units	**67,823**	56,220	53,216

6. TRANSACTIONS WITH AFFILIATES

Affiliate transactions. Revenues from affiliates include amounts earned by the Partnership from midstream services provided to Anadarko as well as from the sale of residue gas, condensate and NGLs to Anadarko, resulting in affiliate transactions. A portion of the Partnership s operating expenses are paid by Anadarko, which also results in affiliate transactions pursuant to the reimbursement provisions of the omnibus agreement described below. In addition, affiliate-based transactions also result from contributions to and distributions from Fort Union, Chipeta and White Cliffs, which are paid or received by Anadarko.

Contribution of partnership assets to the Partnership. Concurrent with the closing of the initial public offering in May 2008, Anadarko contributed the assets and liabilities of AGC, PGT and MIGC to the Partnership. In December 2008, Anadarko contributed the Powder River assets to the Partnership. In July 2009, Anadarko contributed the Chipeta assets to the Partnership. Effective in January 2010, Anadarko contributed the Granger assets to the Partnership, in July 2010 Anadarko contributed the Wattenberg assets to the Partnership, and in September 2010 Anadarko sold AWC, including its 0.4% interest in White Cliffs, to the Partnership. See *Note 1 Description of Business and Basis of Presentation*.

Cash management. Anadarko operates a cash management system whereby excess cash from most of its subsidiaries, held in separate bank accounts, is generally swept to centralized accounts. Prior to our acquisition of the Partnership Assets, except for Chipeta, third-party sales and purchases related to such assets were received or paid in cash by Anadarko within its centralized cash management system. Anadarko charged or credited the Partnership interest at a variable rate on outstanding affiliate balances for the periods these balances remained outstanding. The outstanding affiliate balances were entirely settled through an adjustment to parent net investment in connection with the acquisition of the Partnership Assets, except for Chipeta. Subsequent to our acquisition of the Partnership Assets, except for Chipeta, the Partnership cash-settles transactions related to such assets directly with third parties and with Anadarko affiliates and affiliate-based interest expense on current intercompany balances is not charged.

Prior to June 1, 2008, with respect to Chipeta (the date on which Anadarko initially contributed assets 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 settles transactions directly with third parties and with Anadarko.

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Note receivable from Anadarko. Concurrent with the closing of the Partnership s May 2008 initial public offering, the Partnership loaned $260.0 million to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.50%. Interest on the note is payable quarterly. The fair value of the note receivable from Anadarko was approximately $258.9 million and $271.3 million at December 31, 2010 and December 31, 2009, respectively. The fair value of the note reflects consideration of credit risk and any premium or discount for the differential between the stated interest rate and quarter-end market interest rate, based on quoted market prices of similar debt instruments.

Note payable to Anadarko. Concurrent with the closing of the Powder River acquisition in December 2008, the Partnership entered into a five-year, $175.0 million term loan agreement with Anadarko. The interest rate was fixed at 4.00% through November 2010 and is fixed at 2.82% thereafter. See *Note 11 Debt and Interest Expense Note payable to Anadarko* for additional information.

Credit facilities. From March 2008 through September 2010, the Partnership maintained $100.0 million of availability under Anadarko s credit facility. From May 2008 through September 2010, the Partnership also had a $30.0 million working capital facility with Anadarko. In September 2010, Anadarko entered into a new revolving credit facility, which resulted in elimination of the Partnership s $100.0 million of available borrowing under Anadarko s credit facility and the termination of the Partnership s working capital facility. See *Note 11 Debt and Interest Expense Anadarko s credit facility* and *Working capital facility*.

Commodity price swap agreements. The Partnership entered into commodity price swap agreements with Anadarko to mitigate exposure to commodity price volatility that would otherwise be present as a result of the purchase and sale of natural gas, condensate or NGLs at the Hilight, Hugoton, Newcastle, Granger and Wattenberg assets. The commodity price swap agreements for the Hilight and Newcastle assets were effective in January 2009 and expire in December 2012, with the Partnership able to extend the agreements, at its option, annually through December 2013. The commodity price swap agreements for the Granger assets were effective in January 2010 and extend through December 2014. The commodity price swap agreements for the Wattenberg assets were effective in July 2010 and extend through June 2015. The commodity price swap agreements associated with condensate and natural gas sales and purchases at the Hugoton system were effective in October 2010 and expire in September 2015. Below is a summary of the fixed price ranges on the Partnership s commodity price swap agreements outstanding as of December 31, 2010.

	Year Ended December 31,				
	2011	2012	2013	2014	2015
			(per barrel)		
Ethane	$ 17.95 - 29.31	$ 18.21 - 29.78	$ 18.32 - 30.10	$ 18.36 - 30.53	$ 18.41
Propane	$ 44.25 - 50.07	$ 45.23 - 53.28	$ 45.90 - 51.56	$ 46.47 - 52.37	$ 47.08
Iso butane	$ 58.18 - 66.03	$ 57.50 - 67.22	$ 60.44 - 68.11	$ 61.24 - 69.23	$ 62.09
Normal butane	$ 51.25 - 61.82	$ 52.40 - 62.92	$ 53.20 - 63.74	$ 53.89 - 64.78	$ 54.62
Natural gasoline	$ 68.19 - 75.99	$ 69.77 - 85.15	$ 70.89 - 78.42	$ 71.85 -79.74	$ 72.88
Condensate	$ 68.87 - 75.33	$ 72.73 - 78.52	$ 74.04 - 78.07	$ 75.22 - 79.56	$ 76.47 - 78.61
			(per MMbtu)		
Natural gas	$ 4.12 - 5.94	$ 4.15 - 5.97	$ 5.14 - 6.09	$ 5.32 - 6.20	$ 5.50 - 5.96

The Partnership s notional volumes for each of the swap agreements are not specifically defined; instead, the commodity price swap agreements apply to the actual volume of natural gas, condensate and NGLs purchased and sold at the Hilight, Hugoton, Newcastle, Granger and Wattenberg assets. Because the notional volumes are not fixed, the commodity price swap agreements do not satisfy the definition of a derivative financial instrument at inception and, therefore, are not required to be measured at fair value. The Partnership reports its realized gains and losses on the commodity price swap agreements related to sales in the natural gas, NGLs and condensate sales in its consolidated statements of income in the period in which the associated revenues are recognized. The Partnership reports its realized gains and losses on the commodity price swap agreements related to purchases in cost of product in its consolidated statements of income in the period in which the associated purchases are recorded. The following table summarizes gains and losses on commodity price swap agreements during the years ended December 31, 2010 and 2009 (in thousands):

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	Year Ended December 31,	
	2010	**2009**
Gains (losses) on commodity price swap agreements:		
Natural gas sales	**$ 20,200**	$ 18,446
Natural gas liquids sales	**2,954**	2,196
Gains (losses), net on commodity price swap agreements related to sales	**23,154**	20,642
Gains (losses), net on commodity price swap agreements related to purchases	**(23,345)**	(16,538)
Gains (losses), net on commodity price swap agreements	**$ (191)**	$ 4,104

Chipeta LLC agreement. In connection with the Partnership s acquisition of its 51% membership interest in Chipeta, the Partnership became party to Chipeta s limited liability company agreement, as amended and restated as of July 23, 2009, together with Anadarko and the third-party member. See *Note 3 Noncontrolling Interests*.

Gas gathering and processing agreements. The Partnership has significant gas gathering and/or processing arrangements with affiliates of Anadarko on all of its systems, with the exception of the Highlight and Newcastle systems. Approximately 81%, 80% and 80% of the Partnership s gathering and transportation throughput for the years ended December 31, 2010, 2009 and 2008, respectively, was attributable to natural gas production owned or controlled by Anadarko. Approximately 75%, 71% and 62% of the Partnership s processing throughput for the years ended December 31, 2010, 2009 and 2008, respectively, was attributable to natural gas production owned or controlled by Anadarko.

Gas purchase and sale agreements. The Partnership sells substantially all of its natural gas, NGLs and condensate to Anadarko Energy Services Company (AESC), Anadarko s marketing affiliate. In addition, the Partnership purchases natural gas from AESC pursuant to gas purchase agreements. The Partnership s gas purchase and sale agreements with AESC are generally one-year contracts, subject to annual renewal.

Omnibus agreement. Pursuant to the omnibus agreement, Anadarko and the general partner perform centralized corporate functions for the Partnership, such as legal, accounting, treasury, cash management, investor relations, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, tax, marketing and midstream administration. The Partnership s reimbursement to Anadarko for certain general and administrative expenses allocated to the Partnership was capped at $9.0 million for the year ended December 31, 2010. The consolidated financial statements of the Partnership include costs billed by Anadarko of $9.0 million, $6.9 million and $3.4 million for the years ended December 31, 2010, 2009 and 2008, respectively, in allocated general and administrative expenses subject to the cap contained in the omnibus agreement. In addition, the Partnership s general and administrative expenses for the years ended December 31, 2010 and 2009, included $0.1 million and $0.8 million of expenses incurred by Anadarko and the general partner in excess of the cap contained in the omnibus agreement. Such expenses were recorded as capital contributions from Anadarko and did not impact the Partnership s cash flows. Expenses Anadarko and the general partner incurred on behalf of the Partnership subject to the cap in the omnibus agreement during the year ended December 31, 2008 did not exceed the cap. The Partnership also incurred $8.0 million, $7.5 million and $4.5 million in public company expenses not subject to the cap contained in the omnibus agreement, excluding equity-based compensation, during the years ended December 31, 2010, 2009 and 2008, respectively. The Partnership did not incur public company expenses prior to its initial public offering in May 2008.

The cap under the omnibus agreement expired on December 31, 2010. For the year ending December 31, 2011 and thereafter, Anadarko, in accordance with the partnership agreement and omnibus agreement, will determine in its reasonable discretion amounts to be allocated to the Partnership in exchange for services provided under the omnibus agreement.

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Services and secondment agreement. Pursuant to the services and secondment agreement, specified employees of Anadarko are seconded to the general partner to provide operating, routine maintenance and other services with respect to the assets owned and operated by the Partnership under the direction, supervision and control of the general partner. Pursuant to the services and secondment agreement, the Partnership reimburses Anadarko for services provided by the seconded employees. The initial term of the services and secondment agreement extends through May 2018 and the term will automatically extend for additional twelve-month periods unless either party provides 180 days written notice of termination before the applicable twelve-month period expires. The consolidated financial statements of the Partnership include costs allocated by Anadarko pursuant to the services and secondment agreement for periods including and subsequent to the Partnership s acquisition of the Partnership Assets.

Tax sharing agreement. Pursuant to a tax sharing agreement, the Partnership reimburses Anadarko for the Partnership s estimated share of non-U.S. federal taxes borne by Anadarko on behalf of the Partnership as a result of the Partnership s results being included in a combined or consolidated tax return filed by Anadarko with respect to periods including and subsequent to the Partnership s acquisition of the Partnership Assets. Anadarko may use its tax attributes to cause its combined or consolidated group, of which the Partnership may be a member for this purpose, to owe no tax. Nevertheless, the Partnership is required to reimburse Anadarko for its estimated share of non-U.S. federal tax the Partnership would have owed had the attributes not been available or used for the Partnership s benefit, regardless of whether Anadarko pays taxes for the period.

Allocation of costs. Prior to the Partnership s acquisition of the Partnership Assets, the consolidated financial statements of the Partnership include costs allocated by Anadarko in the form of a management services fee, which approximated the general and administrative costs attributable to the Partnership Assets. This management services fee was allocated to the Partnership based on its proportionate share of Anadarko s assets and revenues or other contractual arrangements. Management believes these allocation methodologies are reasonable.

The employees supporting the Partnership s operations are employees of Anadarko. Anadarko charges the Partnership its allocated share of personnel costs, including costs associated with Anadarko s equity-based compensation plans, non-contributory defined pension and postretirement plans and defined contribution savings plan, through the management services fee or pursuant to the omnibus agreement and services and secondment agreement described above. In general, the Partnership s reimbursement to Anadarko under the omnibus agreement or services and secondment agreements is either (i) on an actual basis for direct expenses Anadarko and the general partner incur on behalf of the Partnership or (ii) based on an allocation of salaries and related employee benefits between the Partnership, the general partner and Anadarko based on estimates of time spent on each entity s business and affairs. The vast majority of direct general and administrative expenses charged to the Partnership by Anadarko are attributed to the Partnership on an actual basis, excluding any mark-up or subsidy charged or received by Anadarko. With respect to allocated costs, management believes that the allocation method employed by Anadarko is reasonable. While it is not practicable to determine what these direct and allocated costs would be on a stand-alone basis if the Partnership were to directly obtain these services, management believes these costs would be substantially the same.

Long-term incentive plan. The general partner awarded phantom units primarily to the general partner s independent directors under the LTIP in May 2010, 2009 and 2008. The phantom units awarded to the independent directors vest one year from the grant date. Compensation expense attributable to the phantom units granted under the LTIP is recognized entirely by the Partnership over the vesting period and was approximately \$0.3 million, \$0.4 million and \$0.3 million for the years ended December 31, 2010, 2009 and 2008, respectively.

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The following table summarizes LTIP award activity for the years ended December 31, 2010, 2009 and 2008:

	2010		2009		2008	
	Value per Unit	Units	Value per Unit	Units	Value per Unit	Units
Phantom units outstanding at beginning of period	$ **15.02**	**21,970**	$ 16.50	30,304	$	
Vested	$ **15.02**	**(19,751)**	$ 16.50	(30,304)	$	
Granted	$ **20.94**	**15,284**	$ 15.02	21,970	$ 16.50	30,304
Phantom units outstanding at end of year	$ **20.19**	**17,503**	$ 15.02	21,970	$ 16.50	30,304

Equity incentive plan and Anadarko incentive plans. The Partnership s general and administrative expenses include equity-based compensation costs allocated by Anadarko to the Partnership for grants made pursuant to the Incentive Plan as well as the Anadarko Incentive Plans. The Partnership s general and administrative expense for the years ended December 31, 2010, 2009 and 2008 included approximately $5.4 million, $4.1 million and $1.9 million, respectively, of allocated equity-based compensation expense for grants made pursuant to the Incentive Plan and Anadarko Incentive Plans. A portion of these expenses are allocated to the Partnership by Anadarko as a component of compensation expense for the executive officers of the Partnership s general partner and other employees pursuant to the omnibus agreement and employees who provide services to the Partnership pursuant to the services and secondment agreement. These amounts exclude compensation expense associated with the LTIP.

Compressor purchase and sale. In September 2010, the Partnership sold idle compressors with a net carrying value of $2.6 million to Anadarko for $2.8 million in cash. The gain on the sale was recorded as an adjustment to Partners capital. In November 2010, the Partnership purchased compressors with a net carrying value of $0.4 million from Anadarko for $0.4 million in cash.

Summary of affiliate transactions. Revenues from affiliates include amounts earned by the Partnership from midstream services provided to Anadarko as well as from the sale of residue gas, condensate and NGLs to Anadarko. A portion of the Partnership s operating expenses are paid by Anadarko, pursuant to the reimbursement provisions under the omnibus agreement described above, which also results in affiliate transactions. Operating expenses include all amounts accrued or paid to affiliates for the operation of the Partnership s assets, whether in providing services to affiliates or to third parties, including field labor, measurement and analysis, and other disbursements. Affiliate expenses do not bear a direct relationship to affiliate revenues and third-party expenses do not bear a direct relationship to third-party revenues. For example, the Partnership s affiliate expenses are not necessarily those expenses attributable to generating affiliate revenues. The following table summarizes affiliate transactions, including transactions with the general partner (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Revenues	**$ 430,069**	$ 410,524	$ 563,707
Operating expenses	**120,668**	127,889	188,591

Interest income affiliates	**16,913**	17,536	12,148
Interest expense	**6,924**	9,096	364
Distributions to unitholders	**52,337**	44,450	15,279
Contributions from noncontrolling interest owners	**2,019**	34,011	130,094 (1)
Distributions to noncontrolling interest owners	**6,476**	5,410	33,335

(1) Includes the $106.2 million initial contribution of assets to Chipeta in connection with Anadarko s formation of Chipeta.

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7. INCOME TAXES

The components of the Partnership s income tax expense (benefit) are as follows (in thousands):

	Year Ended December 31, 2010	2009	2008
Current income tax expense			
Federal income tax expense	**$ 10,687**	$ 19,821	$ 43,233
State income tax expense	**1,535**	1,856	2,117
Total current income tax expense	**12,222**	21,677	45,350
Deferred income tax expense			
Federal income tax expense (benefit)	**(1,528)**	(3,418)	(2,323)
State income tax expense (benefit)	**(122)**	(645)	720
Total deferred income tax expense (benefit)	**(1,650)**	(4,063)	(1,603)
Total income tax expense	**$ 10,572**	$ 17,614	$ 43,747

Total income taxes differed from the amounts computed by applying the statutory income tax rate to income before income taxes. The sources of these differences are as follows (in thousands, except percentages):

	Year Ended December 31, 2010	2009	2008
Income before income taxes	**$ 147,645**	$ 135,780	$ 177,975
Statutory tax rate	**35%**	35%	35%
Tax computed at statutory rate	**51,676**	47,523	62,291
Adjustments resulting from:			
Partnership income not subject to federal taxes	**(41,983)**	(30,563)	(18,919)
State income taxes, net of federal tax benefit	**1,024**	753	2,044
Tax status change			(1,674)
Other	**(145)**	(99)	5
Income tax expense	**$ 10,572**	$ 17,614	$ 43,747
Effective tax rate	**7%**	13%	25%

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The tax effects of temporary differences that give rise to significant portions of deferred tax assets (liabilities) are as follows (in thousands):

	December 31, 2010	December 31, 2009
Net operating loss and credit carryforwards	**$ 14**	$ 14
Other	**2**	778
Net current deferred income tax assets	**16**	792
Depreciable property	**(1,258)**	(219,724)
Net operating loss and credit carryforwards	**570**	585
Other	**(45)**	1,827
Net long-term deferred income tax liabilities	**(733)**	(217,312)
Total net deferred income tax liabilities	**$ (717)**	$ (216,520)

Credit carryforwards, which are available for utilization on future income tax returns consist of $0.6 million of state income tax credits that expire in 2026.

8. CONCENTRATION OF CREDIT RISK

Anadarko was the only customer from whom revenues exceeded 10% of the Partnership s consolidated revenues for the years ended December 31, 2010, 2009 and 2008. The percentages of revenues from Anadarko and the Partnership s other customers are as follows:

	Year Ended December 31, 2010	2009	2008
Anadarko	**84%**	82%	80%
Other customers	**16%**	18%	20%
Total	**100%**	100%	100%

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9. PROPERTY, PLANT AND EQUIPMENT

A summary of the historical cost of the Partnership s property, plant and equipment is as follows (dollars in thousands):

	Estimated useful life	December 31, 2010	December 31, 2009
Land	n/a	**$ 354**	$ 354
Gathering systems	5 to 39 years	**1,621,633**	1,562,273
Pipeline and equipment	30 to 34.5 years	**83,613**	86,617
Assets under construction	n/a	**18,928**	8,713
Other	3 to 25 years	**2,703**	2,340
Total property, plant and equipment		**1,727,231**	1,660,297
Accumulated depreciation		**367,881**	299,309
Total net property, plant and equipment		**$ 1,359,350**	$ 1,360,988

The cost of property classified as Assets under construction is excluded from capitalized costs being depreciated. This amount represents property that is not yet suitable to be placed into productive service as of the balance sheet date. In addition, plant, property and equipment cost as well as accrued liabilities third parties balances in the Partnership s consolidated balance sheets include $5.5 million and $2.8 million of accrued capital as of December 31, 2010 and 2009, respectively, representing estimated capital expenses for which invoices had not yet been processed.

Impairments. Prior to the Partnership s acquisition of the Powder River assets, during the year ended December 31, 2008, a $9.4 million impairment was recognized related to the suspension of operations of a plant that produced iso-butane from NGLs at the Hilight system. Anadarko s management determined the fair value of the asset based on estimates of significant unobservable inputs (a Level 3 fair value measure), including current market values of similar equipment components.

10. ASSET RETIREMENT OBLIGATIONS

The following table provides a summary of changes in asset retirement obligations (in thousands):

	Year Ended December 31, 2010	Year Ended December 31, 2009
Carrying amount of asset retirement obligations at beginning of year	**$ 51,355**	$ 51,303
Additions	**207**	1,884
Settlements	**(104)**	
Accretion expense	**3,427**	3,271
Revisions in estimates	**(14,688)**	(5,103)

Carrying amount of asset retirement obligations at end of year	**$**	**40,197**	$	51,355

Revisions in estimates for the year ended December 31, 2010 related primarily to a decrease in the inflation rate. Revisions in estimates for the year ended December 31, 2009 related primarily to an increase in discount rates, partially offset by higher estimated costs.

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11. DEBT AND INTEREST EXPENSE

The following table presents the Partnership s outstanding debt as of December 31, 2010 and 2009 (in thousands):

	December 31, 2010	December 31, 2009
Revolving credit facility	**$ 49,000**	$
Wattenberg three-year term loan due 2013	**250,000**	
Note payable to Anadarko due 2013	**175,000**	175,000
Total debt outstanding	**$ 474,000**	$ 175,000

The following table presents the debt activity of the Partnership for the years ended 2010 and 2009 (in thousands):

	Principal	Description
Balance as of December 31, 2008	$ 175,000	
Third Quarter 2009		
	101,500	Issuance of three-year term loan
Fourth Quarter 2009		
	100,000	Borrowing under revolving credit facility
	(101,500)	Repayment of three-year term loan
	(100,000)	Repayment under revolving credit facility
Balance as of December 31, 2009	$ 175,000	
First Quarter 2010		
	210,000	Borrowing under revolving credit facility
Second Quarter 2010		
	(100,000)	Repayment under revolving credit facility
Third Quarter 2010		
	200,000	Borrowing under revolving credit facility
	10,000	Borrowing under revolving credit facility Swingline
	250,000	Issuance of Wattenberg term loan
Fourth Quarter 2010		
	(10,000)	Repayment under revolving credit facility Swingline
	(261,000)	Repayment under revolving credit facility
Balance as of December 31, 2010	**$ 474,000**	

Wattenberg term loan. In connection with the Wattenberg acquisition, on August 2, 2010 the Partnership borrowed $250.0 million under a three-year term loan from a group of banks (Wattenberg term loan). The Wattenberg term loan bears interest at London Interbank Offered Rate, or LIBOR, plus a margin ranging from 2.50% to 3.50% depending on the Partnership s consolidated leverage ratio as defined in the Wattenberg term loan agreement. The interest rate was 3.26% at December 31, 2010. The Wattenberg term loan contains various customary covenants, which are substantially similar to those in the Partnership s revolving credit facility described below.

Notes payable to Anadarko.

Five-year term loan. In December 2008, the Partnership entered into a five-year $175.0 million term loan agreement with Anadarko in order to finance the cash portion of the consideration paid for the Powder River acquisition. The interest rate was fixed at 4.00% until November 2010. The term loan agreement was amended in December 2010 to fix the interest rate at 2.82% through maturity of the note in 2013. The Partnership has the option to repay the outstanding principal amount in whole or in part.

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The provisions of the five-year term loan agreement contain customary events of default, including (i) non-payment of principal when due or non-payment of interest or other amounts within three business days of when due, (ii) certain events of bankruptcy or insolvency with respect to the Partnership and (iii) a change of control. At December 31, 2010, the Partnership was in compliance with all covenants under the five-year term loan agreement.

Three-year term loan. In July 2009, the Partnership entered into a $101.5 million, 7.00% fixed-rate, three-year term loan agreement with Anadarko in order to finance the cash portion of the consideration paid for the Chipeta acquisition. The Partnership had the option to repay the outstanding principal amount in whole or in part upon five business days written notice and the Partnership repaid the three-year term loan and accrued interest in October 2009.

Revolving credit facility. In October 2009, the Partnership entered into a three-year senior unsecured revolving credit facility with a group of banks (the revolving credit facility). In connection with the Wattenberg acquisition, the Partnership exercised the accordion feature of its revolving credit facility, expanding the borrowing capacity of the revolving credit facility from $350.0 million to $450.0 million. As of December 31, 2010, $49.0 million was outstanding under the revolving credit facility and $401.0 million was available for borrowing.

The revolving credit facility matures in October 2012 and bears interest at LIBOR, plus applicable margins ranging from 2.375% to 3.250%. The interest rate was 3.26% at December 31, 2010. The Partnership is required to pay a quarterly facility fee ranging from 0.375% to 0.750% of the commitment amount (whether used or unused), based upon the Partnership s consolidated leverage ratio, as defined in the revolving credit facility. The facility fee rate was 0.50% at December 31, 2010.

The revolving credit facility contains covenants that limit, among other things, the ability of the Partnership and certain of its subsidiaries 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 the Partnership s 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. The revolving credit facility also contains various customary covenants, customary events of default and certain financial tests as of the end of each quarter, including a maximum consolidated leverage ratio (which is defined as the ratio of consolidated indebtedness as of the last day of a fiscal quarter to consolidated EBITDA for the most recent four consecutive fiscal quarters ending on such day) of 4.5 to 1.0, and a minimum consolidated interest coverage ratio (which is defined as the ratio of consolidated EBITDA for the most recent four consecutive fiscal quarters to consolidated interest expense for such period) of 3.0 to 1.0. If the Partnership obtains 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 Partnership will no longer be required to comply with the minimum consolidated interest coverage ratio as well as certain of the aforementioned covenants. As of December 31, 2010, the Partnership was in compliance with all covenants under the revolving credit facility.

Anadarko s credit facility. In March 2008, Anadarko entered into a five-year $1.3 billion credit facility (the Anadarko Credit Agreement) under which the Partnership could utilize up to $100.0 million to the extent that such amounts remain available to Anadarko under the credit facility. In September 2010, Anadarko entered into a new revolving credit facility, which resulted in the termination of the Anadarko Credit Agreement, eliminating the Partnership s $100.0 million of available borrowing thereunder.

Working capital facility. In May 2008, the Partnership entered into a two-year $30.0 million working capital facility with Anadarko as the lender. The facility was available exclusively to fund working capital needs. In May 2010, the

Partnership entered into a new two-year $30.0 million working capital facility with Anadarko as the lender. In September 2010, in connection with Anadarko s entry into a new revolving credit facility, the Partnership terminated its working capital facility with Anadarko.

Fair value of debt. The fair value of the Partnership s debt under the revolving credit facility, the Wattenberg term loan and the five-year term loan agreement approximates the carrying value of those instruments at December 31, 2010 and December 31, 2009. The fair value of debt reflects any premium or discount for the difference between the stated interest rate and quarter-end market interest rate.

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Interest expense. The following table summarizes the amounts included in interest expense (in thousands):

	Year Ended December 31,		
	2010	**2009**	**2008**
Third parties			
Interest expense on revolving credit facility and Wattenberg term loan	$ **8,530**	$ 304	$
Revolving credit facility fees and amortization	**3,340**	555	
Total interest expense third parties	**11,870**	859	
Affiliates			
Interest expense on notes payable to Anadarko	**6,828**	8,953	253
Credit facility commitment fees	**96**	143	111
Total interest expense affiliates	**6,924**	9,096	364
Interest expense	**$ 18,794**	$ 9,955	$ 364

12. COMMITMENTS AND CONTINGENCIES

Environmental obligations. The Partnership is subject to various environmental-remediation obligations arising from federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters. As of December 31, 2010, the Partnership s consolidated balance sheet included a $0.4 million current liability and a $0.5 million long-term liability for remediation and reclamation obligations, included in Accrued liabilities third parties and Asset retirement obligations and other, respectively. As of December 31, 2009, the Partnership s consolidated balance sheet included a $0.8 million current liability and a $0.7 million long-term liability for remediation and reclamation obligations. The recorded obligations do not include any anticipated insurance recoveries. Substantially all of the payments related to these obligations are expected to be made over the next five years. Management regularly monitors the remediation and reclamation process and the liabilities recorded and believes the Partnership s environmental obligations are adequate to fund remedial actions to comply with present laws and regulations, and that the ultimate liability for these matters, if any, will not differ materially from recorded amounts nor materially affect the Partnership s overall results of operations, cash flows or financial condition. There can be no assurance, however, that current regulatory requirements will not change, or past non-compliance with environmental issues will not be discovered.

Litigation and legal proceedings. From time to time, the Partnership is involved in legal, tax, regulatory and other proceedings in various forums regarding performance, contracts and other matters that arise in the ordinary course of business. Management is not aware of any such proceeding for which a final disposition could have a material adverse effect on the Partnership s results of operations, cash flows or financial condition.

Lease commitments. Anadarko, on behalf of the Partnership, has entered into lease agreements for corporate offices, shared field offices and a warehouse supporting the Partnership s operations. The lease for the corporate offices expires in January 2012, with no purchase option at termination, and the leases for the shared offices extend through 2014. The lease for the warehouse extends through September 2011 and includes an early termination clause. Anadarko, on behalf of the Partnership, continues to lease certain other compression equipment under leases expiring through January 2015.

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The amounts in the table below represent existing contractual lease obligations for the compression equipment, office and warehouse leases as of December 31, 2010 that may be assigned or otherwise charged to the Partnership pursuant to the reimbursement provisions of the omnibus agreement (in thousands):

	Minimum rental payments
2011	$ 362
2012	205
2013	188
2014	188
2015	188
Total	$ 1,131

Rent expense associated with the office and warehouse leases was approximately $0.4 million for each of the years ended December 31, 2010, 2009 and 2008. In addition, during 2010 prior to the Granger and Wattenberg acquisitions, Anadarko and Kerr-McGee Gathering LLC purchased an aggregate $44.5 million of previously leased compression equipment used at the Granger and Wattenberg assets, which terminated the leases and associated lease expense. The purchased compression equipment was contributed to the Partnership pursuant to provisions of the contribution agreements for the Granger acquisition and the Wattenberg acquisition. Rent expense associated with the previously leased compression equipment was approximately $4.9 million, $8.8 million and $10.2 million for the years ended December 31, 2010, 2009 and 2008, respectively.

13. SUBSEQUENT EVENT

Platte Valley acquisition agreement. In January 2011, the Partnership entered into an agreement to acquire the Platte Valley gathering system and processing plant from a third party for $303.3 million in cash, subject to closing adjustments. These assets are located in the Denver-Julesburg Basin and consist of a processing plant with two cryogenic processing trains; two fractionation trains; gathering systems that deliver gas to the Platte Valley plant, either directly or through the Partnership s Wattenberg gathering system; and related equipment. The Platte Valley gathering system and processing plant are referred to collectively as the Platte Valley assets and the acquisition as the Platte Valley acquisition. In connection with the acquisition, the Partnership will enter into long-term fee-based agreements with the seller to gather and process its existing gas production, as well as to expand the existing gathering systems and processing capacity. The Partnership intends to finance the Platte Valley acquisition with available capacity under its $450.0 million revolving credit facility. The acquisition is expected to close in the first quarter of 2011, subject to regulatory approval and customary closing conditions.

14. CONDENSED CONSOLIDATING FINANCIAL STATEMENTS

As of December 31, 2010, the Partnership may issue up to approximately $771.2 million of additional limited partner common units and various debt securities under its effective shelf registration statement on file with the SEC. Debt securities issued under the shelf may be guaranteed by one or more existing or future subsidiaries of the Partnership (the Guarantor Subsidiaries), each of which is a wholly owned subsidiary of the Partnership. The guarantees, if issued, would be full, unconditional, joint and several. The following condensed consolidating financial information reflects the Partnership s stand-alone accounts, the combined accounts of the Guarantor Subsidiaries, the accounts of the Non-Guarantor Subsidiary, consolidating adjustments and eliminations and the Partnership s consolidated financial information. The condensed consolidating financial information should be read in conjunction with the Partnership s accompanying consolidated financial statements and related notes.

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Western Gas Partners, LP s and the Guarantor Subsidiaries investment in and equity income from their consolidated subsidiaries are presented in accordance with the equity method of accounting in which the equity income from consolidated subsidiaries includes the results of operations of the Partnership Assets for periods including and subsequent to the Partnership s acquisition of the Partnership Assets.

	Year Ended December 31, 2010				
Statement of Income	**Western Gas Partners, LP**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiary**	**Eliminations**	**Consolidated**
			(in thousands)		
Revenues	$ 23,153	$ 436,081	$ 44,088	$	$ 503,322
Operating expenses	44,593	285,445	21,635		351,673
Operating income (loss)	(21,440)	150,636	22,453		151,649
Interest income affiliates	16,869	44			16,913
Interest expense	(18,794)				(18,794)
Other income, net	(2,331)	202	6		(2,123)
Equity income from consolidated subsidiaries	139,613	11,454		(151,067)	
Income before income taxes	113,917	162,336	22,459	(151,067)	147,645
Income tax expense		10,572			10,572
Net income	113,917	151,764	22,459	(151,067)	137,073
Net income attributable to noncontrolling interests		11,005			11,005
Net income attributable to Western Gas Partners, LP	$ 113,917	$ 140,759	$ 22,459	$ (151,067)	$ 126,068

	Year Ended December 31, 2009				
Statement of Income	**Western Gas Partners, LP**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiary**	**Eliminations**	**Consolidated**
			(in thousands)		
Revenues	$ 20,642	$ 427,897	$ 42,007	$	$ 490,546
Operating expenses	34,602	306,729	21,078		362,409

Operating income (loss)		(13,960)		121,168		20,929				128,137
Interest income affiliates		16,883		653						17,536
Interest expense		(9,955)								(9,955)
Other income, net		32		20		10				62
Equity income from consolidated subsidiaries		78,408		4,898				(83,306)		
Income before income taxes		71,408		126,739		20,939		(83,306)		135,780
Income tax expense				17,614						17,614
Net income		71,408		109,125		20,939		(83,306)		118,166
Net income attributable to noncontrolling interests				10,260						10,260
Net income attributable to Western Gas Partners, LP	**$**	71,408	**$**	98,865	**$**	20,939	**$**	(83,306)	**$**	107,906

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Statement of Income	Western Gas Partners, LP	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
	Year Ended December 31, 2008 (in thousands)				
Revenues	$	$ 666,204	$ 32,564	$	$ 698,768
Operating expenses	9,124	507,291	16,361		532,776
Operating income (loss)	(9,124)	158,913	16,203		165,992
Interest income affiliates	10,687	1,461			12,148
Interest expense	(364)				(364)
Other income, net	139	9	51		199
Equity income from consolidated subsidiaries	41,871			(41,871)	
Income before income taxes	43,209	160,383	16,254	(41,871)	177,975
Income tax expense		43,631	116		43,747
Net income	43,209	116,752	16,138	(41,871)	134,228
Net income attributable to noncontrolling interests		7,908			7,908
Net income attributable to Western Gas Partners, LP	$ 43,209	$ 108,844	$ 16,138	$ (41,871)	$ 126,320

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WESTERN GAS PARTNERS, LP
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Balance Sheet	Western Gas Partners, LP	Guarantor Subsidiaries	December 31, 2010 Non-Guarantor Subsidiary (in thousands)	Eliminations	Consolidated
Current assets	$ 24,972	$ 208,208	$ 10,346	$ (200,342)	$ 43,184
Note receivable Anadarko	260,000				260,000
Investment in consolidated subsidiaries	1,052,073	97,018		(1,149,091)	
Net property, plant and equipment	165	1,177,971	181,214		1,359,350
Other long-term assets	2,361	100,642			103,003
Total assets	$ 1,339,571	$ 1,583,839	$ 191,560	$ (1,349,433)	$ 1,765,537
Current liabilities	$ 201,989	$ 38,420	$ 2,127	$ (200,342)	$ 42,194
Long-term debt	474,000				474,000
Other long-term liabilities	38	42,283	1,954		44,275
Total liabilities	676,027	80,703	4,081	(200,342)	560,469
Partners capital	663,544	1,412,674	187,479	(1,149,091)	1,114,606
Noncontrolling interests		90,462			90,462
Total liabilities, equity and partners capital	$ 1,339,571	$ 1,583,839	$ 191,560	$ (1,349,433)	$ 1,765,537

Balance Sheet	Western Gas Partners, LP	Guarantor Subsidiaries	December 31, 2009 Non-Guarantor Subsidiary (in thousands)	Eliminations	Consolidated
Current assets	$ 64,001	$ 64,772	$ 9,425	$ (51,934)	$ 86,264
Note receivable Anadarko	260,000				260,000
Investment in consolidated subsidiaries	497,997	98,959		(596,956)	
Net property, plant and equipment	219	1,176,563	184,206		1,360,988
Other long-term assets	2,974	78,692			81,666

Total assets	$	825,191	$	1,418,986	$	193,631	$	(648,890)	$	1,788,918
Current liabilities	$	52,545	$	33,017	$	1,529	$	(51,934)	$	35,157
Long-term debt		175,000								175,000
Other long-term liabilities				271,067		2,221				273,288
Total liabilities		227,545		304,084		3,750		(51,934)		483,445
Partners capital		597,646		1,023,980		189,881		(596,956)		1,214,551
Noncontrolling interests				90,922						90,922
Total liabilities, equity and partners capital	$	825,191	$	1,418,986	$	193,631	$	(648,890)	$	1,788,918

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WESTERN GAS PARTNERS, LP
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

	Year Ended December 31, 2010				
Statement of Cash Flows	**Western Gas Partners, LP**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiary**	**Eliminations**	**Consolidated**
			(in thousands)		
Cash flows from operating activities					
Net income	**$ 113,917**	**$ 151,764**	**$ 22,459**	**$ (151,067)**	**$ 137,073**
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity income from consolidated subsidiaries	**(139,613)**	**(11,454)**		**151,067**	
Depreciation, amortization and impairments	**54**	**66,982**	**5,757**		**72,793**
Change in other items, net	**149,407**	**(138,888)**	**(3,311)**		**7,208**
Net cash provided by operating activities	**123,765**	**68,404**	**24,905**		**217,074**
Net cash used in investing activities	**(734,780)**	**(86,758)**	**(2,803)**		**(824,341)**
Net cash provided by (used in) financing activities	**570,863**	**18,354**	**(24,860)**		**564,357**
Net decrease in cash and cash equivalents	**(40,152)**		**(2,758)**		**(42,910)**
Cash and cash equivalents at beginning of period	**61,631**		**8,353**		**69,984**
Cash and cash equivalents at end of period	**$ 21,479**	**$**	**$ 5,595**	**$**	**$ 27,074**

	Year Ended December 31, 2009				
Statement of Cash Flows	**Western Gas Partners, LP**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiary**	**Eliminations**	**Consolidated**
			(in thousands)		
Cash flows from operating activities					
Net income	$ 71,408	$ 109,125	$ 20,939	$ (83,306)	$ 118,166

Adjustments to reconcile net income to net cash provided by operating activities:					
Equity income from consolidated subsidiaries	(78,408)	(4,898)		83,306	
Depreciation, amortization and impairments	54	62,226	4,504		66,784
Change in other items, net	2,112	(19,604)	(15,081)	12,493	(20,080)
Net cash provided by (used in) operating activities	(4,834)	146,849	10,362	12,493	164,870
Net cash used in investing activities		(137,043)	(39,378)		(176,421)
Net cash provided by (used in) financing activities	33,157	(9,806)	34,603	(12,493)	45,461
Net increase in cash and cash equivalents	28,323		5,587		33,910
Cash and cash equivalents at beginning of period	33,307		2,767		36,074
Cash and cash equivalents at end of period	$ 61,630	$	$ 8,354	$	$ 69,984

	Year Ended December 31, 2008				
Statement of Cash Flows	**Western Gas Partners, LP**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiary**	**Eliminations**	**Consolidated**
			(in thousands)		
Cash flows from operating activities					
Net income	**$** 43,209	**$** 116,752	**$** 16,138	**$** (41,871)	**$** 134,228
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity income from consolidated subsidiaries	(41,871)			41,871	
Depreciation, amortization and impairments	39	67,993	3,008		71,040
Change in other items, net	51,512	(42,496)	15,004	(12,493)	11,527
Net cash provided by (used in) operating activities	52,889	142,249	34,150	(12,493)	216,795
Net cash used in investing activities	(435,312)	(89,043)	(53,928)		(578,283)
Net cash provided by (used in) financing activities	415,730	(53,206)	22,545	12,493	397,562
	33,307		2,767		36,074

Net increase in cash and cash equivalents					
Cash and cash equivalents at beginning of period					
Cash and cash equivalents at end of period	$ 33,307	$	$ 2,767	$	$ 36,074

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WESTERN GAS PARTNERS, LP

SUPPLEMENTAL QUARTERLY INFORMATION
(Unaudited)

The following table presents a summary of the Partnership s operating results by quarter for the years ended December 31, 2010 and 2009. The Partnership s operating results reflect the operations of the Partnership Assets from the dates of common control. See *Note 1 Description of Business and Basis of Presentation Acquisitions.*

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per unit amounts)			
2010				
Revenues	$ 128,936	$ 124,984	$ 122,292	$ 127,110
Operating income	$ 37,166	$ 37,556	$ 36,887	$ 40,040
Net income attributable to Western Gas Partners, LP	$ 30,438	$ 29,006	$ 31,481	$ 35,143
Net income per limited partner unit (1)	$ 0.37	$ 0.35	$ 0.44	$ 0.46
2009				
Revenues	$ 116,624	$ 126,138	$ 126,053	$ 121,731
Operating income	$ 23,610	$ 34,692	$ 30,967	$ 38,868
Net income attributable to Western Gas Partners, LP	$ 22,673	$ 29,354	$ 25,138	$ 30,741
Net income per limited partner unit (1)	$ 0.30	$ 0.32	$ 0.30	$ 0.33

(1) Includes net income attributable to the Partnership Assets subsequent to the Partnership s acquisition of the Partnership Assets.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. 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 as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934. Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the rules and forms of the SEC and to ensure that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal 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 Partnership s disclosure controls and procedures are effective as of December 31, 2010.

Changes in Internal Control Over Financial Reporting. There has been no change in our internal control over financial reporting during the quarter ended December 31, 2010 that has materially affected, or is reasonably likely to materially affect, the Partnership s internal control over financial reporting.

Item 9B. Other Information

None.

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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.

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.

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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 February 24, 2011. Directors are appointed for a term of one year.

Name	Age	Position with Western Gas Holdings, LLC
Robert G. Gwin	47	Chairman of the Board
Donald R. Sinclair	53	President, Chief Executive Officer and Director
Benjamin M. Fink	40	Senior Vice President, Chief Financial Officer and Treasurer
Danny J. Rea	52	Senior Vice President and Chief Operating Officer
Amanda M. McMillian	38	Vice President, General Counsel and Corporate Secretary
Milton Carroll	60	Director
Anthony R. Chase	55	Director
James R. Crane	57	Director
Charles A. Meloy	50	Director
Robert K. Reeves	53	Director
David J. Tudor	51	Director
R. A. Walker	54	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.

Robert G. Gwin
Age: 47
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 was with Prosoft Learning Corporation, serving as Chairman from 2002 to 2006, Chief Executive Officer and President from 2002 to 2004, and Chief Financial Officer from 2000 to 2004. 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: 53
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.

Benjamin M. Fink
Age: 40
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, and as Senior Vice President, Chief Financial Officer and Treasurer of our general partner since November 2010. 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. 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: 52
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 29 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 served on the board of directors for the Wyoming Pipeline Authority from March 2006 until March 2010 and is a member of the Gas Processors Association and the Society of Petroleum Engineers.

Amanda M. McMillian
Age: 38
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.

Milton Carroll
Age: 60
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), as a director of Halliburton Company, where he serves as a member of the compensation committee and the nominating and corporate governance committee, and as a director of LyondellBasell Industries N.V., where he serves as a member of the audit committee and nominating and governance committee and as chairman of the compensation committee. 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: 55
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, L.P., a Houston-based staffing firm. He served as an Executive Vice President of Crest Investment Company, a Houston-based private equity firm, from January 2009 until December 2009. Prior to these positions, he had most recently served as the Chairman and Chief Executive Officer of ChaseCom, L.P., 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 as a director of AVI Biopharma, Inc. From 1999 to August 2010, he served as a director of Cornell Companies, where he served as a member of the audit committee, and as lead director from May 2008 to August 2010. Beginning in January 2011, Mr. Chase is Vice Chair of the

Greater Houston Partnership and Chairman-Elect for 2012. 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.

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James R. Crane
Age: 57
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 founded and served as 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. Since February 2010, he has served as a director of Fort Dearborn Life Insurance Company, a subsidiary of Health Care Service Corporation. 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: 50
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.

Robert K. Reeves
Age: 53
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 January 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.

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David J. Tudor
Age: 51
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 U.S. 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 U.S. 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.

R. A. Walker
Age: 54
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 as a director of CenterPoint Energy, Inc. since April 2010. Mr. Walker has previously 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.

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 other system on which such securities are traded or quoted, initial reports of ownership and reports of changes in ownership of our common units and other equity securities. Officers, directors and greater-than-10-percent unitholders are required by the SEC s regulations to furnish to us, and any exchange or other system on which such securities are traded or quoted, with copies of all Section 16(a) forms they file with the SEC.

To our knowledge, based solely on a review of the copies of such reports furnished to us and written representations that no other reports were required, we believe that all reporting obligations of our general partner s officers, directors and greater-than-10-percent unitholders under Section 16(a) were satisfied during the year ended December 31, 2010, except that (i) Forms 4 for the insiders participating in the Partnership s equity offering that closed on May 18, 2010 were filed on May 21, 2010, instead of May 20, 2010; and (ii) in January 2011, a late Form 4 was filed for Mr. Crane relating to acquisitions pursuant to a broker-administered distribution reinvestment plan.

Reimbursement of expenses of our general partner and its affiliates

Our general partner does not receive any management fee or other compensation for its management of our Partnership under the omnibus agreement, as amended, the services and secondment agreement or otherwise. Under the omnibus agreement, our reimbursement to Anadarko for certain general and administrative expenses it allocates to us was capped at $9.0 million annually through December 31, 2010. The cap contained in the omnibus agreement did not apply to incremental general and administrative expenses we expect to incur or be allocated to us as a result of being a publicly traded partnership. Please read *Item 13* of this annual report for additional information regarding these agreements.

Board committees

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

Audit Committee

The audit committee is comprised of three independent directors, Messrs. Tudor (chairperson), Chase and Crane, each of whom is able to understand fundamental financial statements and at least one of whom has past experience in accounting or related financial management experience. The board has determined that each member of the audit committee is independent under the NYSE listing standards and the Exchange Act. In making the independence determination, the board considered the requirements of the NYSE and our Code of Business Conduct and Ethics. The audit committee held four meetings in 2010.

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

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

Special Committee

The special committee is comprised of four independent directors, Messrs. Carroll (Chairperson), Chase, Crane and Tudor. The special committee reviews specific matters that the board believes may involve conflicts of interest (including certain transactions with Anadarko). The special committee will determine, as set forth in the partnership agreement, if the resolution of the conflict of interest is fair and reasonable to us. The members of the special committee are not officers or employees of our general partner or directors, officers, or employees of its affiliates, including Anadarko. Our partnership agreement provides that any matters approved in good faith by the special committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. The special committee held ten meetings in 2010.

Meeting of non-management directors and communications with directors

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

The general partner s board of directors welcomes questions or comments about the Partnership and its operations. Unitholders or interested parties may contact the board of directors, including any individual director, at boardofdirectors@westerngas.com or at the following address and fax number: Name of the Director(s), c/o Corporate

Secretary, Western Gas Partners, LP, 1201 Lake Robbins Drive, The Woodlands, Texas 77380, (832) 636-6001.

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Code of ethics, corporate governance guidelines and board committee charters

Our general partner has adopted a Code of Ethics For Chief Executive Officer and Senior Financial Officers, or the Code of Ethics, which applies to our general partner s Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer, Controller and all other senior financial and accounting officers of our general partner. If the general partner amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Partnership will disclose the information on its Internet website. Our general partner has also adopted Corporate Governance Guidelines that outline the important policies and practices regarding our governance and a Code of Business Conduct and Ethics applicable to all employees of Anadarko or affiliates of Anadarko who perform services for us and our general partner.

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

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Item 11. *Executive Compensation*

COMPENSATION DISCUSSION AND ANALYSIS

Overview

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

Some of the officers of our general partner also serve as officers of Anadarko. The compensation (other than the long-term incentive plan benefits described below) of Anadarko s employees that perform services on our behalf, including our executive officers, is approved by Anadarko s management. Awards under our long-term incentive plan are recommended by Anadarko s management and approved by the board of directors of our general partner. Our reimbursement of Anadarko for the compensation of executive officers is governed by, and subject to the limitations contained in, the omnibus agreement and is based on Anadarko s methodology used for allocating general and administrative expenses to us. Under the omnibus agreement, as amended, our reimbursement of certain general and administrative expenses was capped at $9.0 million for 2010. The cap contained in the omnibus agreement did not apply to incremental general and administrative expenses we incurred or that were allocated to us as a result of being a publicly traded partnership. Subsequent to December 31, 2010, general and administrative expenses allocated to us will be determined by Anadarko in its reasonable discretion in accordance with the partnership agreement and omnibus agreement. Please read the caption *Omnibus agreement* under *Item 13* of this annual report.

Our named executive officers for 2010 were Robert G. Gwin (the principal executive officer through January 11, 2010), Donald R. Sinclair (the principal executive officer beginning on January 11, 2010), Benjamin M. Fink (the principal financial officer, principal accounting officer and treasurer), Danny J. Rea (the principal operating officer), Amanda M. McMillian (the vice-president, general counsel and corporate secretary) and Jeremy M. Smith (the vice-president and treasurer until his resignation on November 17, 2010). Compensation paid or awarded by us in 2010 with respect to the named executive officers reflects only the portion of compensation expense that is allocated to us pursuant to Anadarko s allocation methodology and subject to the terms of the omnibus agreement. Anadarko has the ultimate decision-making authority with respect to the total compensation of the named executive officers and, subject to the terms of the omnibus agreement, the portion of such compensation that is allocated to us pursuant to Anadarko s allocation methodology. Generally, once Anadarko has established the aggregate amount to be paid or awarded to the named executive officers with respect to each element of compensation for services rendered to both our general partner and Anadarko, such aggregate amount is multiplied by an allocation percentage for each named executive officer. Each allocation percentage is established based on a periodic, good-faith estimate made by each named executive officer and is reviewed by the chairman of our general partner s board of directors. The resulting amount represents both the amount reimbursed to Anadarko by us pursuant to the terms of the omnibus agreement and the number reflected in the Summary Compensation Table below. Notwithstanding the foregoing, perquisites are not currently allocated to us, and bonus amounts under the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table are capped consistent with the methodology set forth in the Services and Secondment Agreement for other employees whose compensation is allocated to us.

The following table presents the estimated percentage of time, or time allocation, that the general partner s named executive officers devoted to the Partnership during the year ended December 31, 2010 (the percentage representing, for each individual during the time that individual served as a named executive officer of the general partner, the time devoted to the business of the Partnership relative to time devoted to the businesses of the Partnership and Anadarko in the aggregate):

WES Officer	Time Allocated	Anadarko Executive Officer	Anadarko Senior Executive Officer
Robert G. Gwin	0.0%	Yes	Yes
Donald R. Sinclair	75.0%	Yes	No
Benjamin M. Fink	82.5%	No	No
Danny J. Rea	40.0%	Yes	No
Amanda M. McMillian	50.0%	No	No
Jeremy M. Smith[(1)]	33.0%	No	No

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(1) Mr. Smith served as Vice President and Treasurer of our general partner from August 2007 until November 2010 and as Assistant Treasurer, Corporate Finance of Anadarko from July 2006 to until November 2010, when he began serving as Director, Corporate Development of Anadarko.

The following discussion relating to compensation paid by Anadarko is based on information provided to us by Anadarko and does not purport to be a complete discussion and analysis of Anadarko s executive compensation philosophy and practices. For a more complete analysis of the compensation programs and philosophies utilized at Anadarko, please see the Compensation Discussion and Analysis contained within Anadarko s proxy statement, which is expected to be filed with the SEC no later than April 7, 2011. With the exception of the independent director grants under our long-term incentive plan and awards made under the Western Gas Holdings, LLC Amended and Restated Equity Incentive Plan, the elements of compensation discussed below (and Anadarko s decisions with respect to the levels of such compensation), are not subject to approvals by the board of directors of our general partner, including the audit or special committee thereof.

Anadarko s executive compensation program design, principles and process

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

Anadarko s Compensation Committee believes that:

executive interests should be aligned with stockholder interests;

executive compensation should be structured to provide appropriate incentive and reasonable reward for the contributions made and performance achieved; and

a competitive compensation package must be provided to attract and retain experienced, talented executives to ensure Anadarko s success.

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

a majority of total executive compensation should be in the form of equity-based compensation;

a meaningful portion of total executive compensation should be tied directly to the achievement of goals and objectives related to Anadarko s targeted financial and operating performance;

a significant component of performance-based compensation should be tied to long-term relative performance measures that emphasize an increase in stockholder value over time;

performance-based compensation opportunities should not encourage excessive risk taking that may compromise Anadarko s value or its stockholders;

executives should maintain significant levels of equity ownership;

to encourage retention, a substantial portion of compensation should be forfeitable by the executive upon voluntary termination;

total compensation opportunities should be reflective of each executive officer s role, skills, experience level and individual contribution to the organization; and *our executives should be motivated to contribute as team members to Anadarko s overall success, as opposed to merely achieving specific individual objectives.*

Anadarko establishes compensation levels for each executive officer. The level of each element of compensation is generally benchmarked against the 50th and 75th percentiles of Anadarko s industry peer group. In setting compensation levels of each executive officer, Anadarko considers individual experience, individual performance, internal equity, development and/or succession status, and other individual or organizational circumstances, although the percentiles are used as reference points for assessing competitive compensation data rather than for targeting specific compensation amounts. In the case of our named executive officers, Anadarko takes into account the additional duties, as applicable, our executive officers assume in connection with their roles as officers of our general partner.

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With respect to compensation objectives and decisions regarding the named executive officers for 2010, Anadarko s management reviewed market data for determining relevant compensation levels and compensation program elements. In addition, Anadarko s management reviewed and, in certain cases, participated in, various relevant compensation surveys and consulted with compensation consultants with respect to determining 2010 compensation for our named executive officers. All compensation determinations are discretionary and, as noted above, subject to Anadarko s decision-making authority.

Elements of compensation

The primary elements of Anadarko s compensation program are a combination of annual cash and long-term equity-based compensation. For 2010, the principal elements of compensation for the named executive officers are as follows:

base salary;

annual cash incentives;

equity-based compensation, which includes equity-based compensation under Anadarko s 2008 Omnibus Incentive Compensation Plan, or the Omnibus Plan, and the Western Gas Holdings, Amended and Restated LLC Equity Incentive Plan; and

Anadarko s other benefits, including welfare and retirement benefits, severance benefits and change of control benefits, plus other benefits on the same basis as other eligible Anadarko employees.

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

Annual Cash Incentives (Bonuses). Anadarko s management awarded annual cash awards to our named executive officers in 2011 for their performance during the year ended December 31, 2010 under the 2010 Anadarko annual incentive program, or AIP, which is part of Anadarko s Omnibus Plan. Annual cash incentive awards are used by Anadarko to motivate and reward executives for the achievement of Anadarko objectives aligned with value creation and/or to recognize individual contributions to Anadarko s performance. The AIP puts a portion of an executive s compensation at risk by linking potential annual compensation to Anadarko s achievement of specific performance metrics during the year related to operational, financial and safety measures internal to Anadarko. The overall funding for Anadarko s AIP for senior executive officers is capped at 200% of their individual target amount. Anadarko s senior executives may receive up to 200% of their individual bonus target if Anadarko significantly exceeds the specified performance metrics and, conversely, no bonus is paid if Anadarko does not achieve a minimum threshold level of performance. To the extent one of our named executive officers is also an executive officer of Anadarko and files reports under Section 16(a) of the Exchange Act with respect to their Anadarko holdings, the actual bonus awards received by such executive are determined by the compensation and benefits committee, or compensation committee, of Anadarko s board of directors according to Anadarko s, and each such officer s contribution toward, achievement against the established performance metrics. The bonus targets are intended to provide a designated level of compensation opportunity when Anadarko and the officers achieve the specified performance metrics as approved by Anadarko s compensation committee.

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

Long-Term Incentive Awards Under Anadarko s 2008 Omnibus Incentive Compensation Plan. Anadarko periodically makes equity-based awards under its Omnibus Plan to align the interests of its executive officers with those of Anadarko stockholders by emphasizing the long-term growth in Anadarko s value. For 2010, the annual equity awards consisted of a combination of (1) stock options, (2) time-based restricted stock and restricted stock units, and/or (3) performance unit awards. This award structure is intended to provide a combination of equity-based vehicles that is performance-based in absolute and relative terms, while also encouraging retention. The allocated costs we pay for the named executive officers compensation includes costs for a portion of these awards in accordance with the allocation mechanisms in the omnibus agreement.

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Our General Partner s Amended and Restated Equity Incentive Plan. Our general partner has adopted the Amended and Restated Western Gas Holdings, LLC Equity Incentive Plan for the executive officers of our general partner. The awards of unit appreciation rights, unit value rights and distribution equivalent rights made under this plan are designed to provide incentive compensation to encourage superior performance. For a description of this plan, please read the caption *Western Gas Holdings, LLC Amended and Restated Equity Incentive Plan* below within this *Item 11*.

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

retirement benefits to match competitive practices in Anadarko s industry, including Anadarko s Employee Savings Plan, Savings Restoration Plan, Retirement Plan and Retirement Restoration Plan;

severance benefits under the Anadarko Officer Severance Plan;

certain change of control benefits under key employee change of control contracts;

director and officer indemnification agreements;

a limited number of perquisites, including financial counseling, tax preparation and estate planning, an executive physical program, management life insurance, and personal excess liability insurance; and

benefits including medical, dental, vision, flexible spending accounts, paid time off, life insurance and disability coverage, which are also provided to all other eligible U.S.-based Anadarko employees.

For a more detailed summary of Anadarko s executive compensation program and the benefits provided thereunder, please read the caption *Compensation Discussion and Analysis* in Anadarko s proxy statement for its annual meeting of stockholders, which is expected to be filed with the SEC no later than April 7, 2011.

Role of executive officers in executive compensation

Anadarko s compensation committee determines the compensation (other than the long-term incentive plan benefits described above) payable to our named executive officers to the extent such officers are also senior executive officers of Anadarko and Anadarko s management determines the compensation for each of our other named executive officers. The board of directors of our general partner determines compensation for the independent, non-management directors of our general partner s board of directors, as well as any grants made under our long-term incentive plan and its equity incentive plan. None of our named executive officers provide recommendations to the Anadarko compensation committee of Anadarko s management team regarding compensation.

Compensation mix

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

Western Gas Partners, LP 2008 long-term incentive plan

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

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Unit awards. Our general partner s board of directors may grant unit awards to eligible individuals under the LTIP. A unit award is an award of common units that are fully vested upon grant and are not subject to forfeiture.

Restricted units and phantom units. A restricted unit is a common unit that is subject to forfeiture. Upon vesting, the forfeiture restrictions lapse and the recipient holds a common unit that is not subject to forfeiture. A phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of our general partner s board of directors, cash equal to the fair market value of a common unit. Our general partner s board of directors may make grants of restricted and phantom units under the LTIP that contain such terms, consistent with the LTIP, as the board may determine are appropriate, including the period over which restricted or phantom units will vest. The board may, in its discretion, base vesting on the grantee s completion of a period of service or upon the achievement of specified financial objectives or other criteria. In addition, the restricted and phantom units will vest automatically upon a change of control of our general partner (as defined in the LTIP) or as otherwise described in the award agreement. Our general partner s board of directors approved phantom unit grants to each of Messrs. Carroll, Chase, Crane and Tudor in connection with their election to the board. The phantom units granted to each of these directors in 2010 had a grant-date value of approximately $70,000. These phantom units vest on the first anniversary of the date of grant and have tandem distribution equivalent rights.

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

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

Unit options and unit appreciation rights. The LTIP also permits the grant of options covering common units and unit appreciation rights. Unit options represent the right to purchase a number of common units at a specified exercise price. Unit appreciation rights represent the right to receive the appreciation in the value of a number of common units over a specified exercise price, either in cash or in common units as determined by the board. Unit options and unit appreciation rights may be granted to such eligible individuals and with such terms as the board may determine, consistent with the LTIP; however, a unit option or unit appreciation right must have an exercise price greater than or equal to the fair market value of a common unit on the date of grant. No unit options or unit appreciation rights were granted during 2010.

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

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

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

Western Gas Holdings, LLC amended and restated equity incentive plan

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

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

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

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

Vesting of unit appreciation rights. Our general partner s board of directors has the authority to determine the restrictions and vesting provisions for any unit appreciation rights. The initial grants of unit appreciation rights under the Incentive Plan provide for vesting (x) in one-third increments over a three-year period commencing on the first anniversary of the grant date (or in the case of the initial 2009 grant to our current CEO, Mr. Sinclair, in two equal installments on the second and fourth anniversaries of the grant date) or (y) immediately upon the occurrence of any of the following events, if they occur earlier, including: (1) a change of control of our general partner or Anadarko; (2) the closing of an initial public offering of our general partner; (3) termination of employment with our general partner and its affiliates (including Anadarko) due to involuntary termination (with or without cause); (4) death; (5) disability as defined under Section 409A of the Internal Revenue Code of 1986, as amended; or (6) an unforeseeable emergency as defined in the Incentive Plan. Upon the exercise of vested unit appreciation rights each participant will receive a lump-sum cash payment (less any applicable withholding taxes) for each unit appreciation right. Such units must be exercised prior to the earlier of the 90th day after a participant s voluntary termination and the 10th anniversary of the grant date. The unit appreciation rights may not be sold or transferred except to the general partner, Anadarko or any of their affiliates.

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

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

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

Vesting of unit value rights. Our general partner s board of directors has the authority to determine the restrictions and vesting provisions for any unit value rights. The initial grants of unit value rights provide for vesting (x) in one-third increments over a three-year period commencing on the first anniversary of the grant date (or in the case of the initial 2009 grant to our CEO, Mr. Sinclair, in two equal installments on the second and fourth anniversaries of the grant date) or (y) immediately upon the occurrence of any of the following events, if they occur earlier, including: (1) a change of control of our general partner or Anadarko; (2) the closing of an initial public offering of our general partner; (3) termination of employment with our general partner and its affiliates (including Anadarko) due to involuntary termination (with or without cause); (4) death; (5) disability as defined under Section 409A of the Internal Revenue Code of 1986, as amended; or (6) an unforeseeable emergency as defined in the Incentive Plan. Upon the occurrence of a vesting event, each participant will receive a lump-sum cash payment (less any applicable withholding taxes) for each unit value right. The unit value rights may not be sold or transferred except to the general partner, Anadarko or any of their affiliates.

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

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

The following table summarizes information regarding UVRs, UARs and DERs issued under the Incentive Plan for the year ended December 31, 2010:

	UVRs	UARs	DERs
Outstanding at beginning of year	56,667	73,334	73,334
Granted	2,035	2,035	2,035
Vested and settled[1]	(16,667)		
Forfeited			
Outstanding at end of year	42,035	75,369	75,369
Weighted average value at December 31, 2010	$ 57.99	$ 160.54	(2)

(1)

UARs and DERs remain outstanding upon vesting until they are settled in cash, are forfeited or expire. As of December 31, 2010, 33,334 of the outstanding UARs and 3,334 of the DERs were vested.

(2) The DERs have no attributed value as our general partner has not declared or paid distributions since its inception.

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

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EXECUTIVE COMPENSATION

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

Summary compensation table.

The following table summarizes the compensation amounts expensed by us for our general partner s Chief Executive Officer, Chief Financial Officer and the three highest paid executive officers other than our general partner s CEO and CFO for the fiscal years ended December 31, 2010, 2009 and for the period from May 14, 2008 to December 31, 2008, which represents the period following our initial public offering. Except as specifically noted, the amounts included in the table below reflect the expense allocated to us by Anadarko pursuant to the omnibus agreement. For a discussion of the allocation percentages in effect for 2010, please see the Overview section, above.

Name and Principal Position	Year	Salary ($)[(1)]	Bonus ($)	Stock Awards ($)[(2)]	Option Awards ($)[(3)]	Non-Equity Incentive Plan Compensation ($)[(4)]	All Other Compensation ($)[(5)]	Total ($)
Robert G. Gwin [(6)]	2010							
Chairman and Former								
Chief	2009	243,228		157,633	122,275	268,020	83,779	874,935
Executive Officer	2008	107,392		1,140,902	686,012	163,977	28,137	2,126,420
Donald R. Sinclair [(7)]	2010	227,163		492,248	122,400	163,558	86,640	1,092,009
President	2009	56,250		750,000		60,750	24,750	891,750
and Chief Executive Officer								
Benjamin M. Fink [(8)]	2010	225,728		84,129	78,330	121,893	85,870	595,950
Senior Vice President,	2009	120,762		421,120	50,132	72,363	49,069	713,446
Chief Financial Officer and Treasurer								
Danny J. Rea	2010	109,400		205,506	94,603	78,768	41,732	530,009
Senior Vice President	2009	110,416		191,170	82,511	78,970	38,681	501,748
and Chief Operating								
Officer	2008	65,699		468,489	118,861	72,459	17,213	742,721
Amanda M. McMillian	2010	104,798		27,222	25,361	44,015	39,953	241,349
Vice President,								
General Counsel	2009	98,960		27,531	29,961	35,673	35,105	227,230
and Corporate								
Secretary	2008	48,011		270,050		32,049	12,579	362,689
Jeremy M. Smith [(9)]	2010	56,716		3,683	3,423	20,418	21,732	105,972
Former Vice President								
and	2009	66,855		8,512	9,225	23,776	23,219	131,587
Treasurer	2008	46,083		279,136		26,754	12,074	364,047

(1) The amounts in this column reflect the base salary compensation allocated to us by Anadarko for the fiscal years ended December 31, 2010, 2009 and 2008.

(2) The amounts in this column reflect the expected allocation to us of the grant date fair value, computed in accordance with generally accepted accounting principles, for non-option stock awards granted pursuant to the Amended and Restated Western Gas Holdings, LLC Equity Incentive Plan, Anadarko s 2008 Omnibus Incentive Compensation Plan and Anadarko s 1999 Stock Incentive Plan. The awards granted by Western Gas Holdings, LLC in 2010 were valued by multiplying the number of units awarded by the current per unit valuation on the date of grant of $215.00, assuming no forfeitures. The value per unit was based on the estimated fair value of the general partner using a hybrid discounted cash flow and multiples valuation approach. For a discussion of valuation assumptions for the awards under the 2008 Omnibus Incentive Plan, see *Note 12 Stock-Based Compensation* of the notes to consolidated financial statements included under *Item 8* of Anadarko s annual report on Form 10-K for the year ended December 31, 2010. For information regarding the non-option stock awards granted to the named executives in 2010, please see the Grants of Plan-Based Awards Table.

(3) The amounts in this column reflect the expected allocation to us of the grant date fair value, computed in accordance with generally accepted accounting principles, for option awards granted pursuant to the Western Gas Holdings, LLC Amended and Restated Equity Incentive Plan, Anadarko s 2008 Omnibus Incentive Compensation Plan and Anadarko s 1999 Stock Incentive Plan. See note (2) above for valuation assumptions. For information regarding the option awards granted to the named executives in 2010, please see the Grants of Plan-Based Awards Table.

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(4) The amounts in this column reflect the compensation under the Anadarko annual incentive program allocated to us for the fiscal years ended December 31, 2010, 2009 and 2008. The 2010 amounts represent payments which were earned in 2010 and paid in early 2011, the 2009 amounts represent payments which were earned in 2009 and paid in early 2010 and the 2008 amounts represent the payments which were earned in 2008 and paid in early 2009.

(5) The amounts in this column reflect the compensation expenses related to Anadarko s retirement and savings plans that were allocated to us for the fiscal years ended December 31, 2010, 2009 and 2008. The 2010 allocated expenses are detailed in the table below:

Name	Retirement Plan Expense	Savings Plan Expense
Robert G. Gwin	$	$
Donald R. Sinclair	$ 67,937	$ 18,703
Benjamin M. Fink	$ 67,371	$ 18,499
Danny J. Rea	$ 32,722	$ 9,010
Amanda M. McMillian	$ 31,332	$ 8,621
Jeremy M. Smith	$ 17,026	$ 4,706

(6) On October 1, 2009, Mr. Gwin was elected Chairman of our general partner s board of directors and Mr. Sinclair succeeded him as President. On January 11, 2010, Mr. Sinclair succeeded Mr. Gwin as Chief Executive Officer of our general partner. No 2010 values have been disclosed for Mr. Gwin because his allocation percentage for the year was zero, as discussed in the Overview section.

(7) Mr. Sinclair was appointed President on October 1, 2009 and Chief Executive Officer of our general partner on January 11, 2010.

(8) Mr. Fink was appointed Senior Vice President, Chief Financial Officer of our general partner on May 21, 2009 and also Treasurer effective November 17, 2010.

(9) Mr. Smith departed as Vice President and Treasurer of our general partner effective November 17, 2010, to assume the responsibilities associated with his new role as Director, Corporate Development at Anadarko.

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Grants of Plan-Based Awards in 2010

The following table sets forth information concerning annual incentive awards, stock options, unit appreciation rights, unit value rights, restricted stock shares, restricted stock units and performance units granted during 2010 to each of the named executive officers. Except for amounts in the column entitled Exercise or Base Price of Option Awards, the dollar amounts and number of securities included in the table below reflect an allocation based upon the time allocation methodology previously discussed in the Overview section, but also take into account known future changes in the applicable officer s allocation of time to Partnership business.

	Estimated Future Payouts Under Non-Equity Incentive Plan Awards[1]			Estimated Future Payouts Under Equity Incentive Plan Awards[2]			All Other Stock Awards: Number of Shares of Stock or Units	All Other Option Awards: Number of Securities Underlying Options	Exercise or Base Price of Option Awards	Grant Date Fair Value of Stock and Option Awards
Name and Grant Date	Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)	(#)[3]	(#)[4]	($/Sh)	($)[5]
Robert G. Gwin[6]										
Donald R. Sinclair										
		136,298	163,558							
11/17/2010								5,465	62.09	122,400
11/17/2010							2,643			164,104
11/17/2010[7]								1,526	215.00	
11/17/2010[7]							1,526			328,144
Benjamin M. Fink										
		101,578	121,893							
3/5/2010								2,780	72.11	78,330
3/5/2010							1,167			84,129
Danny J. Rea										
		65,640	78,768							
11/9/2010								4,179	63.34	94,603
11/9/2010							1,768			112,010
11/9/2010				341	1,263	2,526				93,496
Amanda M. McMillian										
		36,679	44,015							
3/5/2010								900	72.11	25,361
3/5/2010							378			27,222
Jeremy M. Smith										

	17,015	20,418				
3/5/2010				121	72.11	3,423
3/5/2010			51			3,683

(1) Reflects the estimated 2010 cash payouts allocable to us under Anadarko s annual incentive program. If threshold levels of performance are not met, then the payout can be zero. The maximum value reflects the maximum amount allocable to us consistent with the methodologies set forth in the services and secondment agreement. The expense allocated to us for the actual bonus payouts under the annual incentive program for 2010 are reflected in the *Non-Equity Incentive Plan Compensation* column of the Summary Compensation Table. For additional discussion of Anadarko s annual incentive program please see section *Compensation Discussion and Analysis Elements of Total Compensation Annual Cash Incentives (Bonuses)* of Anadarko s proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 7, 2011.

(2) Reflects the estimated future payout allocable to us under Anadarko s performance units awarded in 2010. Certain Executives may earn from 0% to 200% of the targeted award based on Anadarko s relative TSR performance over a specified performance period. Fifty percent of this award is tied to a two-year performance period and the remaining fifty percent is tied to a three-year performance period. If earned, the awards are to be paid in cash. The threshold value represents the minimum payment (other than zero) that may be earned. For additional discussion of Anadarko s performance unit awards please see section *Compensation Discussion and Analysis Elements of Total Compensation Equity Compensation* of Anadarko s proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 7, 2011.

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(3) Reflects the number of unit value rights, restricted stock shares and restricted stock units awarded in 2010. These awards vest equally over three years, beginning with the first anniversary of the grant date. Executive officers receive distribution equivalent rights on the unit value rights, dividends on the restricted stock shares and dividend equivalents on the restricted stock units.

(4) Reflects the number of stock options and unit appreciation rights each named executive officer was awarded in 2010. These awards vest equally over three years, beginning with the first anniversary of the date of grant. The stock options have a term of seven years and the unit appreciation rights have a term of ten years.

(5) The amounts included in the *Grant Date Fair Value of Stock and Option Awards* column represent the expected allocation to us of the grant date fair value of the awards made to named executives in 2010 computed in accordance with generally accepted accounting principles. The value ultimately realized by the executive upon the actual vesting of the award(s) or the exercise of the unit appreciation right(s) and stock option(s) may or may not be equal to the determined value. The awards granted by Western Gas Holdings, LLC were valued by multiplying the number of units awarded by the current per unit valuation on the date of grant of $215.00, assuming no forfeitures. The value per unit was based on the estimated fair value of the general partner using a hybrid discounted cash flow and multiples valuation approach. For a discussion of valuation assumptions for the awards under Anadarko s 2008 Omnibus Incentive Plan, see *Note 12 Stock-Based Compensation* of the notes to consolidated financial statements included under *Item 8* of Anadarko s annual report on Form 10-K for the year ended December 31, 2010.

(6) No values have been reported for Mr. Gwin because his allocation percentage for 2010 was zero.

(7) These awards were granted under the Western Gas Holdings, LLC Amended and Restated Equity Incentive Plan.

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Outstanding Equity Awards at Fiscal Year-End 2010

The following table reflects outstanding equity awards as of December 31, 2010 for each of the named executives, including both Anadarko and Western Gas Holdings, LLC awards. The market values shown are based on Anadarko s closing stock price on December 31, 2010 of $76.16, unless otherwise noted. Except for amounts in the column entitled Option Exercise Price, the dollar amounts and number of securities included in the table below reflect an allocation based upon each officer s allocation of time to Partnership business on December 31, 2010.

	Option Awards[1]				Stock Awards			
					Restricted Stock Shares/Units and Unit Value Rights[2]		Equity Incentive Plan Awards Performance Units[3]	
Name	Number of Securities Underlying Unexercised Options Exercisable (#)	Number of Securities Underlying Unexercised Options Unexercisable (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Market Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
Robert G. Gwin[4]								
Donald R. Sinclair		5,465	62.09	11/17/2017	15,000[5]	750,000[6]		
	[7]	15,000	50.00	10/1/2019	1,526[5]	328,090[8]		
	[7]	1,526	215.00	11/17/2020	2,643	201,291		
Benjamin M. Fink		1,598	65.99	3/13/2015	959	73,037		
	1,667	3,333	33.07	3/6/2016	1,200	91,392		
		2,831	72.11	3/5/2017	1,188	90,478		
	3,000[7]	6,000	50.00	5/21/2019	6,000[5]	300,000[6]		
Danny J. Rea	2,000		43.56	11/15/2012	1,040	79,206	1,628	123,988
	2,300		48.90	12/1/2013	933	71,057	2,912	221,778
	4,240		59.87	11/6/2014	1,768	134,651	756	57,577
	5,094	2,546	35.18	11/4/2015	1,334[5]	66,700[6]	1,263	96,190
	1,027	2,053	65.44	11/10/2016				
		4,179	63.34	11/9/2017				
	2,666[7]	1,334	50.00	4/2/2018				
	772	1,543	33.07	3/6/2016	821	62,527		

Amanda M. McMillian						
		900	72.11	3/5/2017	555	42,269
	1,667(7)	833	50.00	4/2/2018	378	28,788
					833(5)	41,650(6)
Jeremy M. Smith(4)						

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

Vesting Date	Robert G. Gwin	Donald R. Sinclair	Benjamin M. Fink	Danny J. Rea	Amanda M. McMillian	Jeremy M. Smith
3/5/2011			944		300	
3/6/2011			1,666		772	
3/13/2011			1,598			
4/2/2011				1,334	833	
5/21/2011			3,000			
10/1/2011		7,500				
11/4/2011				2,546		
11/9/2011				1,393		
11/10/2011				1,026		
11/17/2011		2,331				
3/5/2012			944		300	
3/6/2012			1,667		771	
5/21/2012			3,000			
11/9/2012				1,393		
11/10/2012				1,027		
11/17/2012		2,330				
3/5/2013			943		300	
10/1/2013		7,500				
11/9/2013				1,393		
11/17/2013		2,330				

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(2) The table below shows the vesting dates for the respective restricted stock shares, restricted stock units and unit value rights listed in the above Outstanding Equity Awards Table:

Vesting Date	Robert G. Gwin	Donald R. Sinclair	Benjamin M. Fink	Danny J. Rea	Amanda M. McMillian	Jeremy M. Smith
3/5/2011			396		126	
3/6/2011			600		278	
3/13/2011			959		821	
4/2/2011				1,334	833	
5/21/2011			3,000			
10/1/2011		7,500				
11/9/2011				590		
11/10/2011				466		
11/17/2011		1,390				
12/1/2011				1,040		
3/5/2012			396		126	
3/6/2012			600		277	
5/21/2012			3,000			
11/9/2012				589		
11/10/2012				467		
11/17/2012		1,390				
3/5/2013			396		126	
10/1/2013		7,500				
11/9/2013				589		
11/17/2013		1,389				

(3) The table below shows the performance periods for the respective performance units listed in the above Outstanding Equity Awards Table. The number of outstanding units disclosed are calculated based on our performance to date for each award. The estimated payout percents reflect our relative performance ranking as of December 31, 2010 and are not necessarily indicative of what the payout percent earned will be at the end of the performance period. For awards that were granted in 2010 with performance periods beginning in 2011, target payout has been assumed.

Performance Period	Performance to Date Payout %	Danny J. Rea Performance Units
1/1/2008 to 12/31/2010	110%	1,628
1/1/2009 to 12/31/2010	182%	1,456
1/1/2009 to 12/31/2011	182%	1,456
1/1/2010 to 12/31/2011	54%	378
1/1/2010 to 12/31/2012	54%	378
1/1/2011 to 12/31/2012	100%	632
1/1/2011 to 12/31/2013	100%	631

(4) No values have been disclosed for Messrs. Gwin and Smith because their allocation percentages as of December 31, 2010 were zero.

(5)

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

(6) The market value for this award is calculated based on the maximum per-unit value specified under the award agreement of $50.00.

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

(8) The market value for this award is calculated based on the maximum per-unit value specified under the award agreement of $215.00.

Option Exercises and Stock Vested in 2010

The following table reflects Anadarko option awards exercised in 2010 and Anadarko stock awards that vested in 2010. The dollar amounts and number of securities included in the table below reflect an allocation based upon the time allocation previously discussed in the Overview section.

	Option Awards		Stock Awards	
Name	**Number of Shares Acquired on Exercise (#)**	**Value Realized on Exercise ($)(1)**	**Number of Shares Acquired on Vesting (#)(2)**	**Value Realized on Vesting ($)(1)**
Robert G. Gwin (3)				
Donald R. Sinclair (4)				
Benjamin M. Fink	10,684	238,231	3,025	183,690
Danny J. Rea	2,000	68,164	4,400	291,343
Amanda M. McMillian			1,399	90,585
Jeremy M. Smith	238	9,952	826	53,887

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

(2) Shares acquired on vesting include restricted stock shares or units or performance units whose restrictions lapsed during 2010.

(3) No values have been disclosed for Mr. Gwin because his allocation percentage based on his allocation of time to Partnership business for 2010 was zero.

(4) No values have been disclosed for Mr. Sinclair because he did not have any vesting or exercise events in 2010.

Pension Benefits for 2010

Anadarko maintains both funded tax-qualified defined benefit pension plans and unfunded nonqualified pension benefit plans. The nonqualified pension benefit plans are designed to provide for supplementary pension benefits due to limitations imposed by the Internal Revenue Code that restrict the amount of benefits payable under tax-qualified plans. Our named executive officers are eligible to participate in these plans. Under the omnibus agreement a portion of the annual expense related to these plans is allocated to us by Anadarko. The allocated expense for each named executive officer is included in the *All Other Compensation* column of the Summary Compensation Table. We have not included a pension benefits table because the pension benefits accrued through December 31, 2010 may be tied significantly to years of service with Anadarko prior to the time such employee began providing services to the Partnership and are not reflective of the expenses allocated to the Partnership. For additional discussion on Anadarko s pension benefits, please see section *Compensation Discussion and Analysis Elements of Total Compensation Retirement Benefits* of Anadarko s proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 7, 2011.

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Nonqualified Deferred Compensation for 2010

Anadarko maintains a Deferred Compensation Plan and a Savings Restoration Plan for certain employees, including our named executive officers. The Deferred Compensation Plan allows certain employees to voluntarily defer receipt of up to 75% of their salary and/or up to 100% of their annual incentive bonus payments. The Savings Restoration Plan accrues a benefit substantially equal to the amount that, in the absence of certain Internal Revenue Code limitations, would have been allocated to their account as matching contributions under Anadarko s 401(k) Plan. Pursuant to the terms of the omnibus agreement, a portion of the expense related to these plans is allocated to us by Anadarko. The allocated expense for each named executive officer is included in the *All Other Compensation* column of the Summary Compensation Table. We have not included a nonqualified deferred compensation table because the value of an employee s balance may be tied significantly to contributions made prior to the time such employee began providing services to the Partnership and are not reflective of the expenses allocated to the Partnership. For additional discussion on Anadarko s pension benefits please see section *Compensation Discussion and Analysis Elements of Total Compensation Retirement Benefits* of Anadarko s proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 7, 2011.

Potential Payments Upon Termination or Change of Control

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

A Change of Control of Western Gas Holdings, LLC is defined as any one of the following occurrences: (a) any person or group within the meaning of those terms as used in Sections 13(d) and 14(d)(2) of the Exchange Act, other than an Affiliate of the Company, shall become the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of the equity interests in the Company; (b) the members of the Company approve, in one or a series of transactions, a plan of complete liquidation of the Company; or (c) the sale or other disposition by the Company of all or substantially all of its assets in one or more transactions to any Person other than an Affiliate of the Company. For the definition of a Change of Control of Anadarko, please see section *Potential Payments Upon Termination or Change of Control* of Anadarko s proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 7, 2011.

The award values under this Plan as of December 31, 2010 are set forth in the table immediately below, and reflect an allocation of value based upon each officer s allocation of time to Partnership business on December 31, 2010.

Name	**Accelerated Incentive Plan Awards**[1]
Donald R. Sinclair	$ 3,553,144
Benjamin M. Fink	$ 1,290,065
Danny J. Rea	$ 286,724
Amanda M. McMillian	$ 179,095

(1)

Unit value rights are valued based on the maximum value specified under the award agreement. Unit appreciation rights are valued based on the December 31, 2010 per-unit value of $215.00.

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There were no severance payments incurred in connection with Mr. Smith s departure from service with the Partnership or Mr. Gwin s departure from executive service with the Partnership, and no amounts will be allocated to the Partnership with respect to any future severance event for Mr. Smith or Mr. Gwin. Accordingly, the tables in this section do not reflect any severance amounts for Mr. Smith or Mr. Gwin.

We have not entered into any employment agreements with our named executive officers, nor do we manage any severance plans. However, our named executive officers are eligible for certain benefits provided by Anadarko. Currently, we are not allocated any expense for these agreements or plans, but for disclosure purposes we are presenting allocated expenses of the potential payments provided by Anadarko in the event of termination or change of control of Anadarko. Values reflect each named executive officer s allocation of time to Partnership business on December 31, 2010 and exclude those benefits generally provided to all salaried employees. For additional discussion related to these termination scenarios, please see section *Compensation Discussion and Analysis Elements of Total Executive Compensation Severance Benefits* of Anadarko s proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 7, 2011.

The following tables reflect the expenses that may be allocated to the Partnership by Anadarko as of December 31, 2010, in connection with potential payments to our named executive officers under existing contracts, agreements, plans or arrangements, whether written or unwritten, with Anadarko, for various scenarios involving a change of control of Anadarko or termination of employment from Anadarko for each named executive officer, assuming a December 31, 2010 termination date, and, where applicable, using the closing price of Anadarko s common stock of $76.16 (as reported on the NYSE as of December 31, 2010). For general definitions that apply to the termination of employment from Anadarko scenarios detailed below, see section *Potential Payments Upon Termination or Change of Control* of Anadarko s proxy statement for its annual meeting of stockholders which is expected to be filed no later than April 7, 2011. Actual amounts will be determinable only upon the termination or Change in Control event. As of December 31, 2010, none of our executive officers were eligible for retirement; accordingly, no table is included for this event.

Involuntary For Cause or Voluntary Termination

	Mr. Sinclair	**Mr. Fink**	**Mr. Rea**	**Ms. McMillian**
Cash Severance	$	$	$	$
Total	**$**	**$**	**$**	**$**

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Involuntary Not For Cause Termination

	Mr. Sinclair	Mr. Fink	Mr. Rea	Ms. McMillian
Cash Severance[1]	$ 633,750	$	$ 296,400	$
Pro-rata Bonus for 2010[2]	$ 163,558	$	$ 78,768	$
Accelerated Anadarko Equity Compensation[3]	$ 278,176	$ 426,231	$ 679,605	$ 203,679
Accelerated WES Equity Compensation[4]	$ 3,553,144	$ 1,290,065	$ 286,724	$ 179,095
Health and Welfare Benefits[5]	$ 35,579	$	$ 18,378	$
Total	**$ 4,664,207**	**$ 1,716,296**	**$ 1,359,875**	**$ 382,774**

(1) Messrs. Sinclair s and Rea s values assume two times base salary plus one times target bonus multiplied by their allocation percentages in effect as of December 31, 2010. No values have been disclosed for the other named executive officers as they receive the same benefits as generally provided to all salaried employees.

(2) Payment, if provided, will be paid at the end of the performance period based on actual performance. The values for Messrs. Sinclair and Rea reflect the allocated portion of their actual bonuses awarded under Anadarko s annual incentive program for 2010. For additional discussion of this program please see section *Compensation Discussion and Analysis Elements of Total Compensation Annual Cash Incentives (Bonuses)* of Anadarko s proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 7, 2011. No values have been disclosed for the other named executive officers as they receive the same benefits as generally provided to all salaried employees.

(3) Reflects the in-the-money value of unvested stock options, the estimated current value of unvested performance units and the value of unvested restricted stock shares and restricted stock units, under Anadarko equity plans, all as of December 31, 2010. In the event of an involuntary termination, unvested performance units granted prior to 2009 would be paid at target upon termination and all other unvested performance units would be paid after the end of the applicable performance periods based on actual performance. All values reflect each named executive officer s allocation percentage in effect as of December 31, 2010.

(4) Reflects the in-the-money value of unvested unit appreciation rights and the value of unvested unit value rights, granted under the Western Gas Holdings, LLC Amended and Restated Equity Incentive Plan. Unit appreciation rights are valued based on the December 31, 2010 per-unit value of $215.00. Unit value rights are valued based on the maximum value specified under the award agreement. All values reflect each named executive officer s allocation percentage in effect as of December 31, 2010.

(5) Messrs. Sinclair s and Rea s values represent 24 months of health and welfare benefit coverage. These amounts are present values determined in accordance with generally accepted accounting principles. These values reflect their allocation percentage in effect as of December 31, 2010. No values have been disclosed for the other named executive officers as they receive the same benefits as generally provided to all salaried employees.

Change of Control: Involuntary Termination or Voluntary For Good Reason

	Mr. Sinclair		Mr. Fink		Mr. Rea		Ms. McMillian	
Cash Severance[1]	$	1,131,000	$		$	655,400	$	
Pro-rata Bonus for 2010[2]	$	163,558	$		$	78,970	$	
Accelerated Anadarko Equity Compensation[3]	$	278,176	$	426,231	$	728,652	$	203,679
Accelerated WES Equity Compensation[4]	$	3,553,144	$	1,290,065	$	286,724	$	179,095
Supplemental Pension Benefits[5]	$		$		$		$	
Nonqualified Deferred Compensation[6]	$	70,200	$		$	40,680	$	
Health and Welfare Benefits[7]	$	56,532	$		$	27,794	$	
Total	**$**	**5,252,610**	**$**	**1,716,296**	**$**	**1,818,220**	**$**	**382,774**

(1) Messrs. Sinclair s and Rea s values assume 2.9 times the sum of base salary plus the highest bonus paid in the past three years and reflect their allocation percentages in effect as of December 31, 2010, per the terms of their key employee change of control agreements with Anadarko. No values have been disclosed for the other named executive officers as they receive the same benefits as generally provided to all salaried employees.

(2) Messrs. Sinclair s and Rea s values assume the full-year equivalent of their highest annual bonus allocated to us over the past three years. No values have been disclosed for the other named executive officers as they receive the same benefits as generally provided to all salaried employees.

(3) Reflects the in-the-money value of unvested stock options, the target value of unvested performance units, and the value of unvested restricted stock shares and restricted stock units, granted under Anadarko equity plans, all as of December 31, 2010. All values reflect each named executive officer s allocation percentage in effect as of December 31, 2010.

(4) Reflects the in-the-money value of unvested unit appreciation rights and the value of unvested unit value rights, granted under the Western Gas Holdings, LLC Amended and Restated Equity Incentive Plan. Unit appreciation rights are valued based on the December 31, 2010 per-unit value of $215.00. Unit value rights are valued based on the maximum value specified under the award agreement. All values reflect each named executive officer s allocation percentage in effect as of December 31, 2010.

(5) Under the terms of their change of control agreements, Messrs. Sinclair and Rea would receive a special retirement benefit enhancement that is equivalent to the additional supplemental pension benefits that would have accrued under Anadarko s retirement plan assuming they were eligible for subsidized early retirement benefits and include additional special pension credits. The value of this benefit has not been included in the above table because it may be tied significantly to years of service with Anadarko prior to the time such employee began providing service to the Partnership. If Anadarko were to allocate this expense to the Partnership, assuming their allocation percentages in effect as of December 31, 2010, the expense would be as follows: Mr. Sinclair $89,014 and Mr. Rea $546,449.

(6)

Messrs. Sinclair s and Rea s values reflect an additional three years of employer contributions into the Savings Restoration Plan at their current contribution rate to the Plan and are based on their allocation percentages in effect as of December 31, 2010, per the terms of their key employee change of control agreements with Anadarko. No values have been disclosed for the other named executive officers as they are not eligible for this additional benefit.

(7) Messrs. Sinclair s and Rea s values represent 36 months of health and welfare benefit coverage. All amounts are present values determined in accordance with generally accepted accounting principles and reflect their allocation percentages in effect as of December 31, 2010. No values have been disclosed for the other named executive officers as they receive the same benefits as generally provided to all salaried employees.

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Disability

	Mr. Sinclair	Mr. Fink	Mr. Rea	Ms. McMillian
Cash Severance	$	$	$	$
Pro-rata Bonus for 2010(1)	$	$	$	$
Accelerated Anadarko Equity Compensation(2)	$ 278,176	$ 426,231	$ 728,652	$ 203,679
Accelerated WES Equity Compensation(3)	$ 3,553,144	$ 1,290,065	$ 286,724	$ 179,095
Health and Welfare Benefits(4)	$ 140,896	$ 155,086	$ 67,307	$ 31,706
Total	**$ 3,972,216**	**$ 1,871,382**	**$ 1,082,683**	**$ 414,480**

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

(2) Reflects the in-the-money value of unvested stock options, the target value of unvested performance units, and the value of unvested restricted stock shares and restricted stock units, granted under Anadarko equity plans, all as of December 31, 2010. All values reflect each named executive officer s allocation percentage in effect as of December 31, 2010.

(3) Reflects the in-the-money value of unvested unit appreciation rights and the value of unvested unit value rights, granted under the Western Gas Holdings, LLC Amended and Restated Equity Incentive Plan. Unit appreciation rights are valued based on the December 31, 2010 per-unit value of $215.00. Unit value rights are valued based on the maximum value specified under the award agreement. All values reflect each named executive officer s allocation percentage in effect as of December 31, 2010.

(4) Values reflect the continuation of additional death benefit coverage provided to certain employees of Anadarko until age 65. All amounts are present values determined in accordance with generally accepted accounting principles and reflect each named executive officer s allocation percentage in effect as of December 31, 2010.

Death

	Mr. Sinclair	Mr. Fink	Mr. Rea	Ms. McMillian
Cash Severance	$	$	$	$
Pro-rata Bonus for 2010(1)	$	$	$	$
Accelerated Anadarko Equity Compensation(2)	$ 278,176	$ 426,231	$ 728,652	$ 203,679
Accelerated WES Equity Compensation(3)	$ 3,553,144	$ 1,290,065	$ 286,724	$ 179,095
Life Insurance Proceeds(4)	$ 767,113	$ 778,943	$ 358,773	$ 333,596

Total	**$ 4,598,433**	**$ 2,495,239**	**$ 1,374,149**	**$ 716,370**

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

(2) Reflects the in-the-money value of unvested stock options, the target value of unvested performance units, and the value of unvested restricted stock shares and restricted stock units, granted under Anadarko equity plans, all as of December 31, 2010. All values reflect each named executive officer s allocation percentage in effect as of December 31, 2010.

(3) Reflects the in-the-money value of unvested unit appreciation rights and the value of unvested unit value rights, granted under the Western Gas Holdings, LLC Amended and Restated Equity Incentive Plan. Unit appreciation rights are valued based on the December 31, 2010 per-unit value of $215.00. Unit value rights are valued based on the maximum value specified under the award agreement. All values reflect each named executive officer s allocation percentage in effect as of December 31, 2010.

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(4) Values include amounts payable under additional death benefits provided to certain employees of Anadarko. These liabilities are not insured, but are self-funded by Anadarko. Proceeds are not exempt from federal taxes. Values shown include an additional tax gross-up amount to equate benefits with nontaxable life insurance proceeds. Values are based on each named executive officer s allocation percentage in effect as of December 31, 2010 and exclude death benefit proceeds from programs available to all employees.

Director compensation

Officers or employees of Anadarko who also serve as directors of our general partner do not receive additional compensation for their service as a director of our general partner. Non-employee directors of Anadarko receive compensation for their board service and for attending meetings of the board of directors of our general partner and committees of the board pursuant to the director compensation plan approved by the board of directors in May 2010. Such compensation consists of:

- an annual retainer of $40,000 for each board member;
- an annual retainer of $2,000 for each member of the audit committee ($20,000 for the committee chair);
- an annual retainer of $2,000 for each member of the special committee ($20,000 for the committee chair);
- a fee of $2,000 for each board meeting attended;
- a fee of $2,000 for each committee meeting attended; and
- annual grants of phantom units with a value of approximately $70,000 on the date of grant, all of which vest 100% on the first anniversary of the date of grant (with vesting to be accelerated upon a change of control of our general partner or Anadarko).

In addition, each non-employee director is reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or committees. Each director is fully indemnified by us, pursuant to individual indemnification agreements and our partnership agreement, for actions associated with being a director to the fullest extent permitted under Delaware law. On May 25, 2010, the non-employee directors received a grant of phantom units with a value of approximately $70,000.

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The following table sets forth information concerning total director compensation earned during the 2010 fiscal year by each non-employee director:

Name	Fees Earned or Paid in Cash	Stock Awards[(1)]	Option Awards	Non-Equity Incentive Plan Compensation	All Other Compensation	Total
Milton Carroll	$ 98,750	$ 70,002	$	$	$	$ 168,752
Anthony R. Chase	86,000	70,002				156,002
James R. Crane	90,000	70,002				160,002
David J. Tudor	110,750	70,002				180,752

(1) The amounts included in the Stock Awards column represent the grant date fair value of non-option awards made to directors in 2010, computed in accordance with generally accepted accounting principles. For a discussion of valuation assumptions, see Note 6 Transactions with Affiliates Equity-based compensation Long-term incentive plan of the notes to the consolidated financial statements included under Item 8 of this annual report. As of December 31, 2010, each of the non-employee directors had 3,343 outstanding phantom units.

The following table contains the grant date fair value of phantom unit awards made to each non-employee director during 2010:

Name	Grant Date	Phantom Units (#)	Grant Date Fair Value of Stock and Option Awards ($)[(1)]
Milton Carroll	May 25	3,343	70,002
Anthony R. Chase	May 25	3,343	70,002
James R. Crane	May 25	3,343	70,002
David J. Tudor	May 25	3,343	70,002

(1) The amounts included in the *Grant Date Fair Value of Stock and Option Awards* column represent the grant date fair value of the awards made to non-employee directors in 2010 computed in accordance with generally accepted accounting principles. The value ultimately realized by a director upon the actual vesting of the award(s) may or may not be equal to the determined value.

Compensation committee interlocks and insider participation

As previously discussed, our general partner s board of directors is not required to maintain, and does not maintain, a compensation committee. Messrs. Gwin, Meloy, Sinclair, Reeves and Walker, who are directors of our general partner, are also executive officers of Anadarko. However, all compensation decisions with respect to each of these persons are made by Anadarko and none of these individuals receive any compensation directly from us or our general partner for their service as directors. Please read *Item 13* below in this annual report for information about relationships among us, our general partner and Anadarko.

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Compensation committee report

Neither we nor our general partner has a compensation committee. The board of directors of our general partner has reviewed and discussed the Compensation Discussion and Analysis set forth above and based on this review and discussion has approved it for inclusion in this Form 10-K.

The board of directors of Western Gas Holdings, LLC:

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

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

The following tables set forth the beneficial ownership of our units as of February 18, 2011 held by the following:

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

each named executive officer of our general partner;

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

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

Name and address of beneficial owner (1)	Common units beneficially owned(2)	Percentage of common units beneficially owned	Subordinated units beneficially owned	Percentage of subordinated units beneficially owned	Percentage of total common and subordinated units beneficially owned
Anadarko Petroleum Corporation (2)	10,302,631	20.19%	26,536,306	100.00%	47.49%
Western Gas Resources, Inc. (2)	10,302,631	20.19%	26,536,306	100.00%	47.49%
WGR Holdings, LLC (2)	10,302,631	20.19%	26,536,306	100.00%	47.49%
Robert G. Gwin	10,000	*			*
Donald R. Sinclair	100,367	*			*
Benjamin M. Fink	1,324	*			*
Danny J. Rea	11,677	*			*
Amanda M. McMillian		*			*
Jeremy M. Smith	3,800	*			*
Milton Carroll (3)	8,736	*			*
Anthony R. Chase (3)	32,376	*			*
James R. Crane (3)	673,247	1.32%			*
Charles A. Meloy	3,000	*			*
Robert K. Reeves	9,000	*			*
David J. Tudor (3)	12,236	*			*
R. A. Walker	6,000	*			*
All directors and executive officers as a group (12 persons)(3)	867,963	1.70%			*

* Less than 1%

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

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

(3) Does not include 3,343 phantom units that were granted to each of Messrs. Carroll, Chase, Crane and Tudor under the Western Gas Partners, LP 2008 Long-Term Incentive Plan. These phantom units vest 100% on the first anniversary of the date of the grant. Each vested phantom unit entitles the holder to receive a common unit or, in the discretion of our general partner s board of directors, cash equal to the fair market value of a common unit. Holders of phantom units are entitled to distribution equivalents on a current basis. Holders of phantom units have no voting rights until such time as the phantom units become vested and common units are issued to such holders.

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The following table sets forth, as of February 18, 2011, the number of shares of common stock of Anadarko owned by each of the named executive officers and directors of our general partner and all directors and executive officers of our general partner as a group.

Name and address of beneficial owner[(1)]	Shares of common stock owned directly or indirectly[(2)]	Shares underlying options exercisable within 60 days[(2)]	Total shares of common stock beneficially owned[(2)]	Percentage of total shares of common stock beneficially owned[(2)]
Robert G. Gwin[(3)(4)]	5,996	243,367	249,363	*
Donald R. Sinclair[(4)]	843		843	*
Benjamin M. Fink[(4)]	10,508	19,477	29,985	*
Danny J. Rea[(3)(4)]	16,451	36,651	53,102	*
Amanda M. McMillian[(4)]	3,507	3,687	7,194	*
Jeremy M. Smith[(4)]	11,205	1,244	12,449	*
Milton Carroll				*
Anthony R. Chase				*
James R. Crane				*
Charles A. Meloy[(3)(4)]	56,955	136,634	193,589	*
Robert K. Reeves[(3)(4)]	88,303	247,901	336,204	*
David J. Tudor				*
R. A. Walker[(3)(4)]	87,025	368,568	455,593	*
All directors and executive officers as a group (12 persons)	269,588	1,056,285	1,325,873	*

* Less than 1%

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

(2) As of January 31, 2011, there were 496.3 million shares of Anadarko Petroleum Corporation common stock issued and outstanding.

(3) Does not include unvested restricted stock units of Anadarko Petroleum Corporation held by the following executive officers in the amounts indicated: Robert G. Gwin 61,424; Donald R. Sinclair 3,524; Danny J. Rea 9,354; Charles A. Meloy 63,863; Robert K. Reeves 38,170; R. A. Walker 67,914; and a total of 244,249 unvested restricted stock units are held by the directors and executive officers as a group. Restricted stock units typically vest equally over three years beginning on the first anniversary of the date of grant, and upon vesting are payable in Anadarko common stock, subject to applicable tax withholding. Holders of restricted stock units receive dividend equivalents on the units, but do not have voting rights. Generally, a holder will forfeit any unvested restricted units if he or she terminates voluntarily or is terminated for cause prior to the vesting date. Holders of restricted stock units have the ability to defer such awards.

(4) Includes unvested shares of restricted common stock of Anadarko Petroleum Corporation held by the following directors and executive officers in the amounts indicated: Benjamin M. Fink 3,719; Amanda M. McMillian 3,507; Jeremy M. Smith 2,922; and a total of 10,148 unvested shares of restricted common stock are held by the directors and executive officers as a group. Restricted stock awards typically vest equally over three years beginning on the first anniversary of the date of grant. Holders of restricted stock receive dividends on the shares and also have voting rights. Generally, a holder of restricted stock will forfeit any unvested restricted shares if he or she terminates voluntarily or is terminated for cause prior to the vesting date.

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The following table sets forth owners of 5% or greater of our units, other than Anadarko, the holdings of which are listed in the first table of this *Item 12*.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Units	Neuberger Berman Inc. 605 Third Avenue New York, NY 10158	5,523,922 [(1)]	10.82%
Common Units	Kayne Anderson Capital Advisors, L.P. 1800 Avenue of the Stars Second Floor Los Angeles, CA 90067	3,366,059 [(2)]	6.60%

(1) Based upon its Schedule 13G/A filed February 14, 2011 with the SEC with respect to Partnership securities held as of December 31, 2010, Neuberger Berman Group LLC and Neuberger Berman, LLC have shared voting power as to 4,589,748 common units, and shared dispositive power as to 5,523,922 common units.

(2) Based upon its Schedule 13G/A filed February 10, 2011 with the SEC with respect to Partnership securities held as of December 31, 2010, Kayne Anderson Capital Advisors, L.P. and Richard A. Kayne have shared voting power as to 3,366,059 common units and shared dispositive power as to 3,366,059 common units.

Securities authorized for issuance under equity compensation plan

The following table sets forth information with respect to the securities that may be issued under the LTIP as of December 31, 2010. For more information regarding the LTIP, which did not require approval by our unitholders, please read *Note 6 Transactions with Affiliates* included in the notes to the consolidated financial statements under *Item 8* of this annual report and the caption *Western Gas Partners, LP 2008 Long-Term Incentive Plan* included under *Item 11* of this annual report.

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))
Equity compensation plans approved by security holders			
Equity compensation plans not approved by security holders [(1)]	17,503	[(2)]	2,182,442

Total	17,503	2,182,442

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

(2) Phantom units constitute the only rights outstanding under the LTIP. Each phantom unit that may be settled in common units entitles the holder to receive, upon vesting, one common unit with respect to each phantom unit, without payment of any cash. Accordingly, there is no reportable weighted-average exercise price.

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

As of February 18, 2011, our general partner and its affiliates owned 10,302,631 common units and 26,536,306 subordinated units representing an aggregate 46.5% limited partner interest in us. In addition, as of February 18, 2011, our general partner owned 1,583,128 general partner units, representing a 2% general partner interest in us, as well as incentive distribution rights.

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Distributions and payments to our general partner and its affiliates

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

Formation stage

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

Operational stage

Distributions of available cash to our general partner and its affiliates	We will generally make cash distributions of 98.0% to our unitholders pro rata, including Anadarko as the indirect holder of an aggregate 10,302,631 common units and 26,536,306 subordinated units, and 2.0% to our general partner, assuming it makes any capital contributions necessary to maintain its 2.0% interest in us. In addition, if distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner will be entitled to increasing percentages of the distributions, up to 50.0% of the distributions above the highest target distribution level.
Payments to our general partner and its affiliates	Our general partner and its affiliates are entitled to reimbursement for expenses incurred on our behalf, including salaries and employee benefit costs for employees who provide services to us, and all other necessary or appropriate expenses allocable to us or reasonably incurred by our general partner and its affiliates in connection with operating our business. The partnership agreement provides that our general partner determines in good faith the amount of such expenses that are allocable to us.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation stage

Liquidation	Upon our liquidation, our partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements with Anadarko

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

Omnibus agreement

In connection with our initial public offering, we entered into an omnibus agreement with Anadarko and our general partner that addresses the following matters:

- Anadarko s obligation to indemnify us for certain liabilities and our obligation to indemnify Anadarko for certain liabilities;

- our obligation to reimburse Anadarko for expenses incurred or payments made on our behalf in conjunction with Anadarko s provision of general and administrative services to us, including salary and benefits of Anadarko personnel, our public company expenses, general and administrative expenses and salaries and benefits of our executive management who are employees of Anadarko (see *Administrative services and reimbursement* below for details regarding certain agreements for amounts to be reimbursed in 2010); and

- our obligation to reimburse Anadarko for all insurance coverage expenses it incurs or payments it makes with respect to our assets.

The table below reflects the categories of expenses for which the Partnership was obligated to reimburse Anadarko pursuant to the omnibus agreement for the year ended December 31, 2010:

	Year Ended December 31, 2010 (in thousands)	
Reimbursement of general and administrative expenses	$	9,000
Reimbursement of public company expenses	$	4,417
Reimbursement of direct expenses related to acquisitions	$	1,743
Reimbursement of commitment fees	$	96

Any or all of the provisions of the omnibus agreement are terminable by Anadarko at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal. The omnibus agreement will also generally terminate in the event of a change of control of us or our general partner.

Administrative services and reimbursement. Under the omnibus agreement, we reimburse Anadarko for the payment of certain operating expenses and for the provision of various general and administrative services for our benefit with respect to our initial assets and for subsequent acquisitions. The omnibus agreement further provides that we reimburse Anadarko for all expenses it incurs or payments it makes with respect to our assets.

Pursuant to these arrangements, Anadarko performs centralized corporate functions for us, such as legal, accounting, treasury, cash management, 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. We reimburse Anadarko for expenses it incurs or payments it makes on our behalf, including salaries and benefits of Anadarko personnel, our public company expenses, our general and administrative expenses and salaries and benefits of our executive management who are also employees of Anadarko.

Under the omnibus agreement, our reimbursement to Anadarko for certain general and administrative expenses it allocates to us was initially capped at $6.0 million annually. This cap was subsequently modified due to the acquisition of additional assets and was $6.9 million for 2009 and is $9.0 million for the year ending December 31, 2010. Subsequent to December 31, 2010, Anadarko, in accordance with our partnership agreement and the omnibus agreement, will determine in its reasonable discretion amounts to be allocated to us for services provided under the omnibus agreement.

Indemnification with respect to initial assets. Under the omnibus agreement, Anadarko has indemnified us until May 14, 2011 against certain potential environmental claims, losses and expenses associated with the operation of our initial assets, which occurred prior to May 14, 2008 or relate to any investigation, claim or proceeding under environmental laws relating to such assets and pending as of May 14, 2008. Anadarko will have no indemnification obligation with respect to environmental claims on our initial assets made as a result of additions to or modifications of environmental laws that are promulgated after May 14, 2008.

Additionally, Anadarko will indemnify us for losses attributable to the following with respect to our initial assets:

(1) our failure, as of May 14, 2008, to have valid easements, fee title or leasehold interests in and to the lands on which our assets are located, to the extent such failure renders us unable to use or operate our assets in substantially the same manner in which they were used and operated immediately prior to the closing of our initial public offering;

(2) our failure, as of May 14, 2008, to have any consent or governmental permit necessary to allow (i) the transfer of assets from Anadarko to us at May 14, 2008 or (ii) us to use or operate our assets in substantially the same manner in which they were used and operated immediately prior to May 14, 2008;

(3) all income tax liabilities

(i) attributable to the pre-closing operations of our assets,

(ii) arising from or relating to the formation transactions, or

(iii) arising under Treasury Regulation Section 1.1502-6 and any similar provision from state, local or foreign applicable law, by contract, as successor or transferee or otherwise, provided that such income tax is attributable to having been a member of any consolidated, combined or unitary group prior to the closing of our initial public offering;

(4) all liabilities, other than covered environmental laws and other than liabilities incurred in the ordinary course of business conducted in compliance with the applicable laws, that arise prior to May 14, 2008; and

(5) all liabilities attributable to any assets or entities retained by Anadarko.

Anadarko s liability for indemnification is unlimited in amount. Anadarko will not have any obligation to indemnify us, unless a claim for indemnification specifying in reasonable detail the basis for such claim is furnished to us in good faith (a) with respect to a claim under clause (1) or (2) above, prior to the third anniversary date of the closing of our initial public offering or (b) with respect to a claim under clause (3) or (5) above, prior to the first day after expiration of the statute of limitations period applicable to such claim. In no event shall Anadarko be obligated to indemnify us for any losses or income taxes to the extent we have made reservations for any such losses or income taxes in our consolidated financial statements as of December 31, 2007 or to the extent we recover any such losses or income taxes under available insurance coverage or from contractual rights against any third party.

Under the omnibus agreement, we have agreed to indemnify Anadarko for all claims, losses and expenses attributable to operations of our initial assets on or after May 14, 2008, to the extent that such losses are not subject to Anadarko s indemnification obligations.

Indemnification agreements with directors and officers

In connection with our initial public offering, our general partner entered into indemnification agreements with each of its officers and directors (each, an Indemnitee). Each indemnification agreement provides that our general partner will indemnify and hold harmless each Indemnitee against all expense, liability and loss (including attorney s fees, judgments, fines or penalties and amounts to be paid in settlement) actually and reasonably incurred or suffered by the Indemnitee in connection with serving in their capacity as officers and directors of our general partner (or of any subsidiary of our general partner) or in any capacity at the request of our general partner or its board of directors to the fullest extent permitted by applicable law, including Section 18-108 of the Delaware Limited Liability Company Act in effect on the date of the agreement or as such laws may be amended to provide more advantageous rights to the

Indemnitee. The indemnification agreements also provide that our general partner must advance payment of certain expenses to the Indemnitee, including fees of counsel, in advance of final disposition of any proceeding subject to receipt of an undertaking from the Indemnitee to return such advance if it is ultimately determined that the Indemnitee is not entitled to indemnification.

Through December 31, 2010, there have been no payments or claims to Anadarko related to indemnifications and no payments or claims have been received from Anadarko related to indemnifications.

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Services and secondment agreement

In connection with our initial public offering, Anadarko and our general partner entered into a services and secondment agreement pursuant to which specified employees of Anadarko are seconded to our general partner to provide operating, routine maintenance and other services with respect to our business under the direction, supervision and control of our general partner. Pursuant to the services and secondment agreement, our general partner reimburses Anadarko for the services provided by the seconded employees. The initial term of the services and secondment agreement extends through May 2018. The term will extend for additional 12-month periods unless either party provides 180 days written notice otherwise prior to the expiration of the applicable 12-month period. Either party may terminate the agreement at any time upon 180 days written notice.

Tax sharing agreement

In connection with our initial public offering, we entered into a tax sharing agreement pursuant to which we reimburse Anadarko for our estimated share of non-U.S. federal tax borne by Anadarko as a result of our results being included in a combined or consolidated tax return filed by Anadarko with respect to periods subsequent to our acquisition of the Partnership Assets. Anadarko may use its tax attributes to cause its combined or consolidated group, of which we may be a member for this purpose, to owe no tax. Nevertheless, we would be required to reimburse Anadarko for the estimated share of non-U.S. federal tax we would have owed had the attributes not been available or used for our benefit, regardless of whether Anadarko pays taxes for the period.

Related-party acquisition agreements

Powder River assets. On November 11, 2008, we and our subsidiaries entered into the Powder River contribution agreement with Anadarko and several of its affiliates pursuant to which we acquired the Powder River assets from Anadarko. These assets provide a combination of gathering, processing, compressing and treating services in the Powder River Basin of Wyoming and are connected or adjacent to our MIGC pipeline. The consideration consisted of $175.0 million in cash, which was financed by borrowing $175.0 million from Anadarko pursuant to the terms of a five-year term loan agreement, 2,556,891 of our common units and 52,181 of our general partner units. The acquisition closed on December 19, 2008.

Chipeta assets. In July 2009, we and our subsidiaries entered into the Chipeta contribution agreement with Anadarko and several of its affiliates. Pursuant to the agreement, we acquired the Chipeta assets from Anadarko for (i) approximately $101.5 million in cash, which was financed by borrowing $101.5 million from Anadarko pursuant to the terms of a 7.0% fixed-rate, three-year term loan agreement, and (ii) the issuance of 351,424 of our common units and 7,172 of our general partner units. These assets provide processing and transportation services in the Greater Natural Buttes area in Uintah County, Utah. The acquisition consisted of a 51% membership interest in Chipeta Processing LLC (Chipeta), together with associated midstream assets. Chipeta owns a natural gas processing plant complex, which includes two recently completed 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 acquisition closed on July 22, 2009.

Granger assets. In January 2010, we and our subsidiaries entered into the Granger contribution agreement with Anadarko and several of its affiliates. Pursuant to the agreement, we acquired the Granger assets from Anadarko for (i) approximately $241.7 million in cash, which was financed with $210.0 million of borrowings under the Partnership s revolving credit facility plus $31.7 million of cash on hand, and (ii) the issuance of 620,689 of our common units and 12,667 of our general partner units.

White Cliffs acquisition. In September 2010, the Partnership and Anadarko closed a series of related transactions through which the Partnership acquired a 10% member interest in White Cliffs. Specifically, the Partnership acquired Anadarko s 100% ownership interest in Anadarko Wattenberg Company, LLC (AWC) for $20.0 million in cash pursuant to a purchase and sale agreement. AWC owned a 0.4% interest in White Cliffs and held an option to increase its interest in White Cliffs. Also, in a series of concurrent transactions, AWC acquired an additional 9.6% interest in White Cliffs from a third party for $18.0 million in cash, subject to post-closing adjustments. As of September 30, 2010, the Partnership holds a 10% interest in White Cliffs and the remaining 90% is held by three unaffiliated parties.

Wattenberg assets. On August 2, 2010, we and our subsidiaries entered into the Wattenberg contribution agreement with Anadarko and several of its affiliates. Pursuant to the agreement, we acquired certain midstream assets from Anadarko for (i) $473.1 million in cash consideration, which was funded through (a) $250.0 million borrowed under a term loan agreement, (b) $200.0 million borrowed under the Partnership s revolving credit facility, and (c) cash on hand, and (ii) issuance of 1,048,196 of our common units and 21,392 of our general partner units.

Pursuant to the above related-party acquisition agreements, Anadarko has agreed to indemnify us and our respective affiliates (other than any of the entities controlled by Anadarko), shareholders, unitholders, members, directors, officers, employees, agents and representatives against certain losses resulting from any breach of Anadarko s representations, warranties, covenants or agreements, and for certain other matters. We have agreed to indemnify Anadarko and its respective affiliates (other than us and our respective security holders, officers, directors and employees) and their respective security holders, officers, directors and employees against certain losses resulting from any breach of our representations, warranties, covenants or agreements made in such agreements.

The board of directors of our general partner approved the acquisition of the Powder River assets, the Chipeta assets, the Granger assets, the Wattenberg assets and AWC, based in part on the recommendations in favor of the acquisitions from, and the granting of special approval under our partnership agreement by, the board s special committee. The special committee, a committee of independent members of our general partner s board of directors, retained independent legal and financial advisors to assist it in evaluating and negotiating the acquisitions. In recommending the approval of the acquisitions, the special committee based its decision, in part, on the independent financial advisors written opinions representing that the consideration to be paid by us to Anadarko was fair.

Chipeta LLC agreement

In connection with the Partnership s acquisition of its 51% membership interest in Chipeta, the Partnership became party to Chipeta s limited liability company agreement, as amended and restated as of July 23, 2009, together with Anadarko and the third-party member. Among other things, the Chipeta LLC agreement provides that:

Chipeta s members will be required from time to time to make capital contributions to Chipeta to the extent approved by the members in connection with Chipeta s annual budget;

Chipeta will distribute available cash, as defined in the Chipeta LLC agreement, if any, to its members quarterly in accordance with those members membership interests; and

Chipeta s membership interests are subject to significant restrictions on transfer.

Upon acquisition of out interest in Chipeta, we became the managing member of Chipeta. As managing member, we manage the day-to-day operations of Chipeta and receive a management fee from the other members, which is intended to compensate the managing member for the performance of its duties. We may only be removed as the managing member if we are grossly negligent or fraudulent, breach our primary duties or fail to respond in a commercially reasonable manner to written business proposals from the other members, and such behavior, breach or failure has a material adverse effect to Chipeta.

Note payable to Anadarko

In connection with the acquisition of the Powder River assets, we entered into a term loan agreement under which Anadarko loaned $175.0 million to us to fund a portion of the acquisition cost. The term loan agreement has a term of five years and the interest rate was fixed at 4% through November 2010. During the year ended December 31, 2010, we incurred approximately $6.8 million in interest on the loan. The term loan agreement was amended in

December 2010 to fix the interest rate at 2.82% through maturity of the note in 2013. We have the option to repay the amount due in whole or in part commencing upon the second anniversary of the term loan agreement. The provisions of the term loan agreement are non-recourse to our general partner and our limited partners and contain customary events of default, including (i) nonpayment of principal when due or nonpayment of interest or other amounts within three business days of when due, (ii) certain events of bankruptcy or insolvency with respect to the Partnership, or (iii) a change of control. The term loan agreement also contains a full guaranty of the amounts due by a wholly owned subsidiary of Anadarko.

Note receivable from Anadarko

In connection with our initial public offering, we loaned $260.0 million to Anadarko. The note is a 30-year note bearing interest at a fixed annual rate of 6.5%, payable quarterly, with principal and all accrued and unpaid interest due in full at maturity.

Commodity price swap agreements

We have entered into commodity price swap agreements with Anadarko to mitigate exposure to commodity price volatility that would otherwise be present as a result of our acquisition of certain Partnership Assets. Specifically, the commodity price swap agreements fix the margin we will realize under substantially all percent-of-proceeds and keep-whole contracts at the Hilight, Newcastle, Granger, Wattenberg and Hugoton systems. In this regard, our notional volumes for each of the swap agreements are not specifically defined; instead, the commodity price swap agreements apply to volumes of natural gas, condensate and NGLs sold and purchased at these systems. The commodity prices we will realize under the specified contracts are fixed for various terms through September 2015. See *Note 6 Transactions with Affiliates Commodity price swap agreements* in the notes to the consolidated financial statements under *Item 8* of this annual report for information on commodity price swap agreements entered into by the Partnership.

Gas gathering and processing agreements

We have significant gas gathering and/or processing arrangements with affiliates of Anadarko on all of our systems, with the exception of the Highlight and Newcastle systems. Approximately 81% of our gathering and transportation throughput and 75% of our processing throughput for the year ended December 31, 2010 was attributable to natural gas production owned or controlled by Anadarko.

Gas purchase and sale agreements

Substantially all natural gas, NGLs and condensate are sold to Anadarko Energy Services Company (AESC), Anadarko s marketing affiliate, pursuant to sales agreements. In addition, we purchase natural gas and NGLs from AESC pursuant to gas purchase agreements. Our gas purchase and sale agreements with AESC are generally one-year contracts, subject to annual renewal.

Compressor purchase and sale

In September 2010, we sold idle compressors with a net carrying value of $2.6 million to Anadarko for $2.8 million in cash. The gain on the sale was recorded as an adjustment to Partners capital. In November 2010, we purchased compressors with a net carrying value of $0.4 million from Anadarko for $0.4 million in cash.

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Summary of affiliate transactions

Revenues from affiliates include amounts earned by us from midstream services provided to Anadarko, as well as from the sale of residue gas, condensate and NGLs to Anadarko. A portion of our operating expenses are paid by Anadarko, pursuant to the reimbursement provisions under the omnibus agreement, which also results in affiliate transactions. Operating expenses include all amounts accrued or paid to affiliates for the operation of our systems, whether in providing services to affiliates or to third parties, including field labor, measurement and analysis, and other disbursements. Affiliate expenses do not bear a direct relationship to affiliate revenues and third-party expenses do not bear a direct relationship to third-party revenues. For example, our affiliate expenses are not necessarily those expenses attributable to generating affiliate revenues. The following table summarizes affiliate transactions, including transactions with the general partner.

	Year Ended December 31,		
	2010	2009	2008
	(in thousands)		
Revenues	**$ 430,069**	$ 410,524	$ 563,707
Operating expenses	**120,668**	127,889	188,591
Interest income	**16,913**	17,536	12,148
Interest expense	**6,924**	9,096	364
Distributions to unitholders	**52,337**	44,450	15,279
Contributions from noncontrolling interest owners	**2,019**	34,011	130,094(1)
Distributions to noncontrolling interest owners	**6,476**	5,410	33,335

(1) Includes the $106.2 million initial contribution of assets to Chipeta in connection with Anadarko s formation of Chipeta.

Conflicts of interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates, including Anadarko, on the one hand, and our partnership and our limited partners, on the other hand. The directors and officers of our general partner have fiduciary duties to manage our general partner in a manner beneficial to its owners. At the same time, our general partner has a fiduciary duty to manage our partnership in a manner beneficial to us and our unitholders.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us and our limited partners, on the other hand, our general partner will resolve the conflict. Our partnership agreement contains provisions that modify and limit our general partner s fiduciary duties to our unitholders. Our partnership agreement also restricts the remedies available to our unitholders for actions taken by our general partner that, without those limitations, might constitute breaches of its fiduciary duty. See the caption *Special Committee* under *Item 10* of this annual report.

Our general partner will not be in breach of its obligations under the partnership agreement or its fiduciary duties to us or our unitholders if the resolution of the conflict is either:

approved by the special committee of our general partner, although our general partner is not obligated to seek such approval;

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

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

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

Our general partner may, but is not required to, seek the approval of such resolution from the special committee of its board of directors. In connection with a situation involving a conflict of interest, any determination by our general partner involving the resolution of the conflict of interest must be made in good faith, provided that, if our general partner does not seek approval from the special committee and its board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth bullet points above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the special committee may consider any factors that it determines in good faith to be appropriate when resolving a conflict. Our partnership agreement provides that for someone to act in good faith, that person must reasonably believe he is acting in the best interests of the partnership.

Item 14. *Principal Accounting Fees and Services*

We have engaged KPMG LLP as our independent registered public accounting firm. The following table summarizes the fees we have paid KPMG LLP to audit the Partnership s annual consolidated financial statements and for other services for each of the last two fiscal years:

		2010		2009
		(in thousands)		
Audit fees	$	**920**	$	915
Audit-related fees		**640**		289
Tax				
All other fees				
Total	$	**1,560**	$	1,204

Audit fees are primarily for the audit of the Partnership s consolidated financial statements, including the audit of the effectiveness of the Company s internal controls over financial reporting, and reviews of the Partnership s financial statements included in the Form 10-Qs.

Audit-related fees are primarily for other audits, consents, comfort letters and certain financial accounting consultation. The above amounts represent fees paid by the Partnership.

Audit Committee approval of audit and non-audit services

The Audit Committee of the Partnership s general partner has adopted a Pre-Approval Policy with respect to services that may be performed by KPMG LLP. This policy lists specific audit-related services as well as any other services that KPMG LLP is authorized to perform and sets out specific dollar limits for each specific service, which may not be exceeded without additional Audit Committee authorization. The Audit Committee receives quarterly reports on the status of expenditures pursuant to that Pre-Approval Policy. The Audit Committee reviews the policy at least annually in order to approve services and limits for the current year. Any service that is not clearly enumerated in the policy must receive specific pre-approval by the Audit Committee or by its Chairman, to whom such authority has been conditionally delegated, prior to engagement. During 2010, no fees for services outside the scope of audit, review, or attestation that exceed the waiver provisions of 17 CFR 210.2-01(c)(7)(i)(C) were approved by the Audit Committee.

The Audit Committee has approved the appointment of KPMG LLP as independent registered public accounting firm to conduct the audit of the Partnership s consolidated financial statements for the year ended December 31, 2011.

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PART IV

Item 15. Exhibits

(a)(1) *Financial Statements*

Our consolidated financial statements are included under *Item 8* of this annual report. For a listing of these statements and accompanying footnotes, please see the *Index to Consolidated Financial Statements* under *Item 8* of this annual report.

(a)(2) *Financial Statement Schedules*

Our supplemental quarterly information is included under Part II, *Item 8* of this annual report.

(a)(3) *Exhibits*

Exhibit Index

Exhibit Number	Description
2.1	Contribution, Conveyance and Assumption Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, Anadarko Petroleum Corporation, WGR Holdings, LLC, Western Gas Resources, Inc., WGR Asset Holding Company LLC, Western Gas Operating, LLC and WGR Operating, LP, dated as of May 14, 2008 (incorporated by reference to Exhibit 10.2 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
2.2#	Contribution Agreement, dated as of November 11, 2008, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on November 13, 2008, File No. 001-34046).
2.3#	Contribution Agreement, dated as of July 10, 2009, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, Anadarko Uintah Midstream, LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on July 23, 2009, File No. 001-34046).
2.4#	Contribution Agreement, dated as of January 29, 2010 by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, Mountain Gas Resources LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on February 3, 2010 File No. 001-34046).
2.5#	Contribution Agreement, dated as of July 30, 2010, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on August 5, 2010, File No. 001-34046).

2.6#	Purchase and Sale Agreement, dated as of January 14, 2011, by and among Western Gas Partners, LP, Kerr-McGee Gathering LLC and Encana Oil & Gas (USA) Inc. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on January 18, 2011 File No. 001-34046).
3.1	Certificate of Limited Partnership of Western Gas Partners, LP (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Registration Statement on Form S-1 filed on October 15, 2007, File No. 333-146700).
3.2	First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated May 14, 2008 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
3.3	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP dated December 19, 2008 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).
3.4	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated as of April 15, 2009 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on April 20, 2009, File No. 001-34046).

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Exhibit Number	Description
3.5	Amendment No. 3 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP dated July 22, 2009 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on July 23, 2009, File No. 001-34046).
3.6	Amendment No. 4 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP dated January 29, 2010 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on February 3, 2010, File No. 001-34046).
3.7	Amendment No. 5 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated August 2, 2010 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on August 5, 2010, File No. 001-34046).
3.8	Certificate of Formation of Western Gas Holdings, LLC (incorporated by reference to Exhibit 3.3 to Western Gas Partners, LP s Registration Statement on Form S-1 filed on October 15, 2007, File No. 333-146700).
3.9	Amended and Restated Limited Liability Company Agreement of Western Gas Holdings, LLC, dated as of May 14, 2008 (incorporated by reference to Exhibit 3.2 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
4.1	Specimen Unit Certificate for the Common Units (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP s Quarterly Report on Form 10-Q filed on June 13, 2008, File No. 001-34046).
10.1	Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC and Anadarko Petroleum Corporation, dated as of May 14, 2008 (incorporated by reference to Exhibit 10.3 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.2	Amendment No. 1 to Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, and Anadarko Petroleum Corporation, dated as of December 19, 2008 (incorporated by reference to Exhibit 10.2 to Western Gas Partners, LP s Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).
10.3	Amendment No. 2 to Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, and Anadarko Petroleum Corporation, dated as of July 22, 2009 (incorporated by reference to Exhibit 10.2 to Western Gas Partners, LP s Current Report on Form 8-K filed on July 23, 2009, File No. 001-34046).
10.4	Amendment No. 3 to Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, and Anadarko Petroleum Corporation, dated as of December 31, 2009 (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on January 7, 2010, File No. 001-34046).
10.5	Amendment No. 4 to Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, and Anadarko Petroleum Corporation, dated as of January 29, 2010 (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on February 3, 2010, File No. 001-34046).
10.6	Amendment No. 5 to Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, and Anadarko Petroleum Corporation, dated as of August 2, 2010 (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on August 5, 2010, File No. 001-34046).
10.7	Services And Secondment Agreement between Western Gas Holdings, LLC and Anadarko Petroleum Corporation dated May 14, 2008 (incorporated by reference to Exhibit 10.4 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).

10.8	Tax Sharing Agreement by and among Anadarko Petroleum Corporation and Western Gas Partners, LP, dated as of May 14, 2008 (incorporated by reference to Exhibit 10.5 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.9	Anadarko Petroleum Corporation Fixed Rate Note due 2038 (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.10	Form of Commodity Price Swap Agreement (filed as Exhibit 10.3 to the Partnership s Form 10-Q for the quarter ended March 31, 2010).
10.11	Term Loan Agreement due 2013 dated as of December 19, 2008 by and between Anadarko Petroleum Corporation and Western Gas Partners, LP (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).
10.12	Amendment No. 1 to Term Loan Agreement due 2013 dated December 20, 2010 by and between Anadarko Petroleum Corporation and Western Gas Partners, LP.

Exhibit Number	Description
10.13	Form of Indemnification Agreement by and between Western Gas Holdings, LLC, its Officers and Directors (incorporated by reference to Exhibit 10.10 to Amendment No. 2 to Western Gas Partners, LP s Registration Statement on Form S-1 filed on January 23, 2008, File No. 333-146700).
10.14	Western Gas Partners, LP 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.13 to Western Gas Partners, LP s Quarterly Report on Form 10-Q filed on June 13, 2008, File No. 001-34046).
10.15	Form of Award Agreement under the Western Gas Partners, LP 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.9 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.16	Amended and Restated Western Gas Holdings, LLC Equity Incentive Plan (incorporated by reference to Exhibit 10.3 to Western Gas Partners, LP s Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).
10.17	Form of Amended and Restated Award Agreement under Western Gas Holdings, LLC Equity Incentive Plan (incorporated by reference to Exhibit 10.4 to Western Gas Partners, LP s Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).
10.18	Amended and Restated Limited Liability Company Agreement of Chipeta Processing LLC effective July 23, 2009 (incorporated by reference to Exhibit 10.4 to Western Gas Partners, LP s Quarterly Report on Form 10-Q filed on November 12, 2009, File No. 001-34046).
10.19	Revolving Credit Agreement, dated as of October 29, 2009, among Western Gas Partners, LP, Wells Fargo Bank National Association, as the administrative agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on October 30, 2009, File No. 001-34046).
10.20	Term Loan Agreement dated August 2, 2010, by and among the Partnership, as borrower, Wells Fargo Bank, National Association, as administrative agent, DnB NOR Bank ASA, as syndication agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to Western Gas Partners, LP s Current Report on Form 8-K filed on August 5, 2010, File No. 001-34046).
12.1*	Ratio of Earnings to Fixed Charges.
21.1*	List of Subsidiaries of Western Gas Partners, LP.
23.1*	Consent of KPMG LLP.
31.1*	Certification of Chief Executive Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

\# Pursuant to Item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted schedule to the Securities and Exchange Commission upon request.

Portions of this exhibit, which was previously filed with the Securities and Exchange Commission, were omitted pursuant to a request for confidential treatment. The omitted portions were filed separately with the Securities and Exchange Commission.

Management contracts or compensatory plans or arrangements required to be filed pursuant to *Item 15*.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WESTERN GAS PARTNERS, LP
(Registrant)

By: Western Gas Holdings, LLC, its general partner

By: */s/ Benjamin M. Fink*

Benjamin M. Fink
Senior Vice President, Chief Financial Officer
and Treasurer
(Principal Financial and Accounting Officer)

Date: February 24, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on February 24, 2011.

Signature	Title (Position with Western Gas Holdings, LLC)
/s/ Robert G. Gwin Robert G. Gwin	Chairman and Director
/s/ Donald R. Sinclair Donald R. Sinclair	President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ Benjamin M. Fink Benjamin M. Fink	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)
/s/ R. A. Walker R. A. Walker	Director
/s/ Charles A. Meloy Charles A. Meloy	Director
/s/ Robert K. Reeves Robert K. Reeves	Director

/s/ Milton Carroll	Director
Milton Carroll	
/s/ Anthony R. Chase	Director
Anthony R. Chase	
	Director
James R. Crane	
/s/ David J. Tudor	Director
David J. Tudor	

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