Western Gas Partners LP
Form 10-K
February 26, 2015

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, 2014

Or

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

For the transition period from to

Commission file number: 001-34046

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

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

(832) 636-6000
(Registrant’s telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Units Representing Limited Partner Interests	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes 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 þ 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.

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

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 registrant's common units representing limited partner interests held by non-affiliates of the registrant was $5.2 billion on June 30, 2014, based on the closing price as reported on the New York Stock Exchange.

At February 23, 2015, there were 127,695,130 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE
None

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DEFINITIONS

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

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

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

Bbls/d: Barrels per day.

Bcf: One billion cubic feet.

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.

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

Cryogenic: The process in which liquefied gases, such as liquid nitrogen or liquid helium, are used to bring volumes to very low temperatures (below approximately –238 degrees Fahrenheit) 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 for end-use sale.

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.

Gpm: Gallons per minute, when used in the context of amine treating capacity.

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.

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Joule-Thompson (JT) plant: A type of processing plant that uses the Joule-Thompson effect to cool natural gas by expanding the gas from a higher pressure to a lower pressure which reduces the temperature.
MBbls/d: One thousand barrels per day.
MMBtu: One million British thermal units.
MMBtu/d: One million British thermal units per day.
MMcf: One million cubic feet.
MMcf/d: One million cubic feet per day.
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.
Play: A group of gas or oil fields that contain known or potential commercial amounts of petroleum and/or natural gas.
Receipt point: The point where volumes are received by or into a gathering system, processing facility or transportation pipeline.
Refrigeration plant: a method of processing natural gas by reducing the gas temperature with the use of an external refrigeration system.
Residue: The natural gas remaining after the unprocessed natural gas stream has been processed or treated.
Sour gas: Natural gas containing more than four parts per million of hydrogen sulfide.
Stabilization: The process of separating very light hydrocarbon gases, methane and ethane in particular, from heavier hydrocarbon components. This process reduces the volatility of condensates/crude oil during transportation and storage. Typically, stabilized condensate / oil has a vapor pressure of less than 11 pounds per square inch, absolute, and a Reid Vapor Pressure of less than 10 pounds per square inch.
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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PART I

Items 1 and 2. Business and Properties

GENERAL OVERVIEW

Western Gas Partners, LP, a growth-oriented Delaware master limited partnership ("MLP") formed by Anadarko Petroleum Corporation in 2007 to own, operate, acquire and develop midstream energy assets, closed its initial public offering ("IPO") to become publicly traded in 2008. For purposes of this report, the "Partnership," "we," "our," "us" or like ter refers to Western Gas Partners, LP and its subsidiaries. We are engaged in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, NGLs and crude oil for Anadarko Petroleum Corporation and its consolidated subsidiaries, as well as third-party producers and customers. Our common units are publicly traded on the New York Stock Exchange ("NYSE") under the symbol "WES."

The Partnership's general partner, Western Gas Holdings, LLC (the "general partner" or "GP"), is owned by Western Gas Equity Partners, LP ("WGP"), a Delaware MLP formed by Anadarko Petroleum Corporation in September 2012 to own our general partner, as well as a significant limited partner interest in us. WGP's common units are publicly traded on the NYSE under the symbol "WGP." Western Gas Equity Holdings, LLC is WGP's general partner and is a wholly owned subsidiary of Anadarko Petroleum Corporation. "Anadarko" refers to Anadarko Petroleum Corporation and its subsidiaries, excluding us and our general partner, and "affiliates" refers to subsidiaries of Anadarko, excluding us, and includes equity interests in Fort Union Gas Gathering, LLC ("Fort Union"), White Cliffs Pipeline, LLC ("White Cliffs"), Rendezvous Gas Services, LLC ("Rendezvous"), Enterprise EF78 LLC (the "Mont Belvieu JV"), Texas Express Pipeline LLC ("TEP"), Texas Express Gathering LLC ("TEG") and Front Range Pipeline LLC ("FRP"). The interests in TEP, TEG and FRP are referred to collectively as the "TEFR Interests." All income earned on, distributions from and contributions to, our equity investments are considered to be affiliate transactions. "Equity investment throughput" refers to our 14.81% share of average Fort Union throughput and 22% share of average Rendezvous throughput, but excludes throughput measured in barrels, consisting of our 10% share of average White Cliffs throughput, 25% share of average Mont Belvieu JV throughput, 20% share of average TEP and TEG throughput and 33.33% share of average FRP throughput. "MIGC" refers to MIGC LLC, and "Chipeta" refers to Chipeta Processing LLC. The "DJ Basin complex" refers to the Platte Valley system, Wattenberg system and Lancaster plant, all of which were combined into a single complex in the first quarter of 2014.

Available information. We electronically file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other documents with the U.S. Securities and Exchange Commission ("SEC") under the Securities Exchange Act of 1934, as amended. From time to time, we may also file registration and related statements pertaining to equity or debt offerings.

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 website 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 website at www.sec.gov.

Our Corporate Governance Guidelines, Code of Ethics for our Chief Executive Officer and Senior Financial Officers, Code of Business Conduct and Ethics and the charters of the Audit Committee and the Special Committee of our general partner's Board of Directors are also available on our 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.

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OUR ASSETS AND AREAS OF OPERATION

As of December 31, 2014, our assets and investments accounted for under the equity method consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Natural gas gathering systems	14	1	5	2
Natural gas treating facilities	8	—	—	1
Natural gas processing facilities	13	3	—	2
NGL pipelines	3	—	—	3
Natural gas pipelines	4	—	—	—
Oil pipeline	1	—	—	1

These assets and investments are located in the Rocky Mountains (Colorado, Utah and Wyoming), the Mid-Continent (Kansas and Oklahoma), North-central Pennsylvania and Texas. The following table provides information regarding our assets by geographic region, as of and for the year ended December 31, 2014, excluding Train II at our Lancaster plant which is currently under construction in Northeast Colorado and Train IV at the DBM complex, which is currently preparing for construction in West Texas and was acquired with the acquisition of DBM (see Acquisitions below and Assets Under Development within these Items 1 and 2):

Area	Asset Type	Miles of Pipeline (1)	Approximate Number of Active Receipt Points (1)	Gas Compression (HP) (1)	Processing or Treating Capacity (MMcf/d) (1) (2)	Average Gathering, Processing and Transportation Throughput (MMcf/d) (3)	Average Gathering, Processing and Transportation Throughput (MBbls/d) (4)
Rocky Mountains	Gathering, Processing and Treating	7,732	5,044	482,108	3,161	2,258	—
	Transportation	1,037	41	28,002	—	99	35
Mid-Continent	Gathering	2,067	1,498	90,214	—	66	—
North-central Pennsylvania	Gathering	632	368	70,750	—	805	—
Texas	Gathering, Processing and Treating	1,060	1,017	61,000	1,000	430	—
	Transportation	1,145	12	34,395	—	—	81
Total		13,673	7,980	766,469	4,161	3,658	116

(1) All system metrics are presented on a gross basis.

(2) Capacity excludes 170 MBbls/d of fractionation capacity attributable to the Mont Belvieu JV.

(3) Includes 100% of Chipeta throughput, 50% of Newcastle throughput, 22% of Rendezvous throughput and 14.81% of Fort Union throughput.

(4) Represents total throughput measured in barrels, consisting of throughput from our Chipeta NGL pipeline, our 10% share of average White Cliffs throughput, our 25% share of average Mont Belvieu JV throughput, our 20% share of average TEG and TEP throughput and our 33.33% share of average FRP throughput. See Properties below for further descriptions of these systems.

Our operations are organized into a single operating segment that engages in gathering, processing, compressing, treating and transporting Anadarko and third-party natural gas, condensate, NGLs and crude oil in the United States. See Item 8 of this Form 10-K for disclosure of revenues, profits and total assets for the years ended December 31, 2014, 2013 and 2012.

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ACQUISITIONS

Acquisitions. The following table presents our acquisitions during 2014, and identifies the funding sources for such acquisitions. See Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

thousands except unit and percent amounts	Acquisition Date	Percentage Acquired	Borrowings	Cash On Hand	Common Units Issued to Anadarko	Class C Units Issued to Anadarko [3]
TEFR Interests [1]	03/03/2014	Various [1]	$350,000	$6,250	308,490	—
DBM [2]	11/25/2014	100 %	475,000	298,327	—	10,913,853

(1) We acquired a 20% interest in each of TEG and TEP and a 33.33% interest in FRP from Anadarko. These assets gather and transport NGLs primarily from the Anadarko and Denver-Julesburg ("DJ") Basins. TEG consists of two NGL gathering systems that link natural gas processing plants to TEP. TEP is an NGL pipeline that originates in Skellytown, Texas and extends approximately 593 miles to Mont Belvieu, Texas. FRP is a 435-mile NGL pipeline that extends from Weld County, Colorado to Skellytown, Texas. The interests in these entities are accounted for under the equity method of accounting. In connection with the issuance of the common units, our general partner purchased 6,296 general partner units in exchange for the general partner's proportionate capital contribution of $0.4 million.

(2) We acquired Nuevo Midstream, LLC ("Nuevo") from a third party. Following the acquisition, we changed the name of Nuevo to Delaware Basin Midstream, LLC ("DBM"). The assets acquired include cryogenic processing plants, a gas gathering system, and related facilities and equipment, which are collectively referred to as the "DBM complex" and serve production from Reeves, Loving and Culberson Counties, Texas and Eddy and Lea Counties, New Mexico.

(3) See Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K for a discussion of the Class C units.

Presentation of Partnership assets. The term "Partnership assets" refers to the assets owned and interests accounted for under the equity method (see Note 9—Equity Investments in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K) by us as of December 31, 2014. Because Anadarko controls us through its ownership and control of WGP, which owns the entire interest in our general partner, each of our acquisitions of Partnership assets from Anadarko has been considered a transfer of net assets between entities under common control. As such, the Partnership assets we acquired from Anadarko were initially recorded at Anadarko's historic carrying value, which did not correlate to the total acquisition price paid by us (see Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K). Further, after an acquisition of Partnership assets from Anadarko, we may be required to recast our financial statements to include the activities of such Partnership assets from the date of common control.

EQUITY OFFERINGS

Equity offerings. We completed the following public equity offerings during 2014:

thousands except unit and per-unit amounts	Common Units Issued	GP Units Issued [1]	Price Per Unit	Underwriting Discount and Other Offering Expenses	Net Proceeds
Continuous Offering Program - 2014 [2]	1,133,384	23,132	$73.48	$1,738	$83,245
November 2014 equity offering [3]	8,620,153	153,061	70.85	18,583	602,999

(1)

Represents general partner units issued to the general partner in exchange for the general partner's proportionate capital contribution.

(2) Represents common and general partner units issued during the year ended December 31, 2014, pursuant to our registration statement filed with the SEC in August 2012 authorizing the issuance of up to $125.0 million of common units (the "Continuous Offering Program"). Gross proceeds generated (including the general partner's proportionate capital contributions) during the year ended December 31, 2014, were $85.0 million. The price per unit in the table above represents an average price for all issuances under the Continuous Offering Program during the year ended December 31, 2014. As of December 31, 2014, the Partnership had used all the capacity to issue common units under this registration statement.

(3) Includes the issuance of 1,120,153 common units pursuant to the partial exercise of the underwriters' over-allotment option. Net proceeds from this partial exercise were $77.0 million. Beginning with this partial exercise, our general partner elected not to make a corresponding capital contribution to maintain a 2.0% interest in us. See Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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Other equity offerings. In November 2014, we issued 10,913,853 Class C units to a subsidiary of Anadarko at an implied price of $68.72 per unit, generating proceeds of $750.0 million, all of which was used to fund a portion of the acquisition of DBM. See Note 3—Partnership Distributions and Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

STRATEGY

Our primary business objective is to continue to increase our cash distributions per unit over time. To accomplish this objective, we intend to execute the following strategy:

- Pursuing accretive acquisitions. We expect to continue to pursue accretive acquisitions of midstream energy assets 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. We continually evaluate economically attractive organic expansion opportunities in existing or new areas of operation that allow us to leverage our existing infrastructure, operating expertise and customer relationships by constructing and expanding systems to meet new or increased demand of our services.

- Attracting third-party volumes to our systems. We expect to continue to actively market our midstream services to, and pursue strategic relationships with, third-party producers and customers 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 and promote cash flow stability by pursuing a contract structure designed to mitigate exposure to a substantial majority of the commodity price uncertainty through the use of fee-based contracts and fixed-price hedges.

- Maintaining investment grade ratings. We intend to operate at appropriate leverage and distribution coverage levels in line with other partnerships in our sector that have received investment grade credit ratings. By maintaining an investment grade credit rating with all three credit rating agencies, in part through staying within leverage ratios appropriate for investment-grade partnerships, we believe that we will be able to pursue strategic acquisitions and large growth projects at a lower cost of fixed-income capital, which would enhance their accretion and overall return.

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 is motivated to promote and support the successful execution of our business plan and to use its relationships throughout the energy industry, including those with producers and customers in the United States, to pursue projects that help to enhance the value of our business. See Our Relationship with Anadarko Petroleum Corporation below.

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- Relatively stable and predictable cash flows. Our cash flows are largely protected from fluctuations caused by commodity price volatility due to (i) the approximately 80% of our services that are provided pursuant to long-term, fee-based agreements and (ii) the commodity price swap agreements that limit our exposure to commodity price changes with respect to a substantial majority of our percent-of-proceeds and keep-whole contracts. For the year ended December 31, 2014, 99% of our gross margin was derived from either long-term, fee-based contracts or from percent-of-proceeds or keep-whole agreements that were hedged with commodity price swap agreements. On December 31, 2014, our commodity price swap agreements for the Hilight and Newcastle systems and the Granger complex expired without renewal. On June 30, 2015, and September 30, 2015, our commodity price swap agreements for the DJ Basin complex and Hugoton system, respectively, will expire. See Risk Factors under Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

- Financial flexibility to pursue expansion and acquisition opportunities. We believe our operating cash flows, borrowing capacity, and access to debt and equity capital markets provide us with the financial flexibility to competitively pursue acquisition and expansion opportunities and to execute our strategy across capital market cycles. We currently have investment grade ratings from all three of the major rating agencies and, as of December 31, 2014, we had $510.0 million of outstanding borrowings and $12.8 million in outstanding letters of credit issued under our $1.2 billion senior unsecured revolving credit facility (“RCF”).

- Substantial presence in basins with historically strong producer economics. Certain of our gathering and processing systems and facilities, such as the DBM complex, the DJ Basin complex and the Brasada complex serve production in liquids-rich growth areas where the hydrocarbon production contains not only natural gas, but also oil, condensate, and significant amounts of NGLs. Production in liquids-rich areas offers our customers higher margins and superior economics compared to basins in which the gas is predominantly dry. In addition, our interests in the Anadarko-Operated and Non-Operated Marcellus gathering systems serve dry gas production from the Marcellus shale, which historically has provided attractive producer returns due to the overall scale and quality of the underlying resource, as well as its access to premium markets in the northeast United States. See Properties below for further asset descriptions.

- Well-positioned, well-maintained and efficient assets. We believe that our asset portfolio, which is located in geographically diverse areas of operation, provides us with opportunities to expand and attract additional volumes to our systems from multiple productive reservoirs. Moreover, our portfolio includes an integrated package of high-quality, well-maintained assets for which we have implemented modern processing, treating, measuring and operating technologies.

- Consistent track record of accretive acquisitions. Since our IPO in 2008, our management team has successfully executed nine related-party acquisitions and six third-party acquisitions, with an aggregate value of $4.8 billion. Our management team has demonstrated its ability to identify, evaluate, negotiate, consummate and integrate strategic acquisitions and expansion projects, and it intends to use its experience and reputation to continue to grow the Partnership through accretive acquisitions, focusing on opportunities to improve throughput volumes and cash flows.

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

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OUR RELATIONSHIP WITH ANADARKO PETROLEUM CORPORATION

Our operations and activities are managed by our general partner, which is indirectly controlled by Anadarko through WGP. Anadarko 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 believe that one of our principal strengths is our relationship with Anadarko, and that Anadarko, through its significant indirect economic interest in us, will continue to be motivated to promote and support the successful execution of our business plan and to pursue projects that help to enhance the value of our business.

For the year ended December 31, 2014, 48% of our gathering, transportation and treating throughput (excluding equity investment throughput and throughput measured in barrels) was attributable to natural gas production owned or controlled by Anadarko, and 57% of our processing throughput (excluding equity investment throughput and throughput measured in barrels) was attributable to natural gas production owned or controlled by Anadarko. In addition, with respect to the Wattenberg, Dew, Pinnacle, Haley, Helper, Clawson and Hugoton gathering systems, Anadarko has made a dedication to us that will continue to expand as long as additional wells are connected to these gathering systems. In executing our growth strategy, which includes acquiring and constructing additional midstream assets, we use the significant experience of Anadarko's management team.

As of December 31, 2014, WGP held 49,296,205 of our common units, representing a 34.9% limited partner interest in us, and, through its ownership of our general partner, indirectly held 2,583,068 general partner units, representing a 1.8% general partner interest in us, and 100% of our incentive distribution rights ("IDRs"). As of December 31, 2014, other subsidiaries of Anadarko held 757,619 common units and 10,913,853 Class C units, representing an aggregate 8.3% limited partner interest in us. As of December 31, 2014, the public held 77,641,306 common units, representing a 55.0% limited partner interest in us.

In connection with our IPO, we entered into an omnibus agreement with Anadarko and our general partner that governs our relationship with Anadarko regarding certain reimbursement and indemnification matters. Although we believe our relationship with Anadarko provides us with a significant advantage in the midstream energy sector, it is also a source of potential conflicts. For example, neither Anadarko nor WGP is restricted from competing with us. Given Anadarko's significant indirect economic interest in us through its ownership of WGP, we believe it will be in Anadarko's best economic 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 participate in such transactions. Should Anadarko choose to pursue additional midstream asset sales, it is under no contractual obligation to offer assets or business 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 Risk Factors under Item 1A and Certain Relationships and Related Transactions, and Director Independence under Item 13 of this Form 10-K for more information.

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INDUSTRY OVERVIEW

The midstream natural gas industry is the link between the exploration for and production of natural gas and the delivery of the resulting 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 primary 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.

- Stabilization. In connection with our gathering services, we sometimes retain, stabilize and sell drip condensate, which falls out of the natural gas stream during gathering. Stabilization is a process that separates the heavier hydrocarbons (which also serve as valuable commodities) found in natural gas, typically referred to as “liquids-rich” natural gas, from the lighter components by using a distillation process or by reducing the pressure and letting the more volatile components flash. We provide stabilization for condensate at many of our processing plants (such as the DJ Basin and Brasada complexes).

- 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 water vapor or contaminants, such as carbon dioxide and hydrogen sulfide, it is dehydrated to remove the saturated water and treated to separate the carbon dioxide and hydrogen sulfide from the gas stream.

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- Processing. Processing separates the heavier and more valuable hydrocarbon components, which are extracted as NGLs, from the remaining residue. The remaining residue is then designated for long-haul pipeline transportation or commercial use.

- Fractionation. Fractionation is the process of applying various levels of higher pressure and lower temperature to separate a stream of NGLs into ethane, propane, normal butane, isobutane and natural gasoline for end-use sale.

- Storage, transportation and marketing. Once the raw natural gas has been treated or processed and the raw NGL 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 better accommodate seasonal demand and daily supply-demand shifts. We do not currently offer storage services.

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 and/or NGLs or a percentage of the actual residue 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.

Two forms of contracts are used 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 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K for information regarding our contracts.

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PROPERTIES

The following sections describe in more detail the services provided by our assets in our areas of operation as of December 31, 2014.

GATHERING, PROCESSING AND TREATING

Overview - Rocky Mountains - Wyoming

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Location	Asset	Type	Processing / Treating Plants	Processing / Treating Capacity (MMcf/d)	Compressor Stations	Compression Horsepower	Gathering Systems	Pipeline Miles
Northeast Wyoming	Bison	Treating	1	450	—	14,320	—	—
Northeast Wyoming	Fort Union (1)	Gathering & Treating	1	294	—	5,454	1	318
Northeast Wyoming	Hilight	Gathering & Processing	1	60	13	37,357	1	1,563
Northeast Wyoming	Newcastle (1)	Gathering & Processing	1	3	1	2,660	1	180
Southwest Wyoming	Granger complex (2)	Gathering & Processing	2	500	8	43,950	1	896
Southwest Wyoming	Red Desert complex (3)	Gathering & Processing	2	173	9	62,262	1	1,110
Southwest Wyoming	Rendezvous (4)	Gathering	—	—	1	7,485	1	338
Total			8	1,480	32	173,488	6	4,405

(1) We have a 14.81% interest in Fort Union and a 50% interest in Newcastle.
(2) The Granger complex includes the "Granger straddle plant," a refrigeration processing plant.
(3) The Red Desert complex includes the Patrick Draw cryogenic processing plant and the Red Desert cryogenic processing plant.
(4) We have a 22% interest in the Rendezvous gathering system, which is operated by a third party.

Northeast Wyoming

Bison treating facility

- Customers. Anadarko provided 67% of the throughput at the Bison treating facility for the year ended December 31, 2014. The remaining throughput was from one third-party producer.

- Supply and delivery points. The Bison treating facility treats and compresses gas from coal-bed methane wells in the Powder River Basin of Wyoming. The Bison pipeline, operated by TransCanada Corporation, is connected directly to the facility, which is currently the only inlet into the pipeline. The Bison treating facility also has access to Fort Union's pipeline and Meritage Midstream Services II, LLC's Thunder Creek pipeline.

Fort Union gathering system and treating facility

- Customers. Anadarko and the other members of Fort Union (Copano Pipelines/Rocky Mountains, LLC, Crestone Powder River LLC, and Bargath, LLC) are the only firm shippers on the Fort Union system. To the extent capacity on the system is not used by the members, it is available to third parties under interruptible agreements.

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Supply. Substantially all of Fort Union's gas supply is comprised of coal-bed methane volumes that are either produced or gathered by the customers noted above throughout the Powder River Basin. As of December 31, 2014, the Fort Union system gathered gas from 1,900 Anadarko-operated coal-bed methane wells producing in the Big George coal play and a nearby multi-seam coal fairway. Anadarko had a working interest in over 1.1 million gross acres within the Powder River Basin as of December 31, 2014. 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 hub in Glenrock, Wyoming, which has access to the following interstate pipelines:

- Colorado Interstate Gas Company LLC's pipeline ("CIG");
- Tallgrass Interstate Gas Transmission system's pipeline ("TIGT"); and
- Wyoming Interstate Company's pipeline ("WIC").

These pipelines serve gas markets in the Rocky Mountains and Midwest regions of the United States.

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Hilight gathering system and processing plant

- Customers. Gas gathered and processed through the Hilight system is primarily from numerous third-party customers, with the six largest producers providing 71% of the system throughput during the year ended December 31, 2014.

- Supply. The Hilight gathering system serves the gas gathering needs of several conventional producing fields in Johnson, Campbell, Natrona and Converse Counties. Our customers, including Anadarko, have historically maintained and more recently increased throughput by developing new prospects and performing workovers.

- Delivery points. The Hilight plant delivers residue into our MIGC transmission line (see Transportation within these Items 1 and 2). Hilight is not connected to an active NGL pipeline, resulting in all fractionated NGLs being sold locally through its truck and rail loading facilities.

Newcastle gathering system and processing plant

- Customers. Gas gathered and processed through the Newcastle system is from 11 third-party customers, with the largest three producers providing 80% of the system throughput during the year ended December 31, 2014. The largest producer provided 57% of the throughput during the year ended December 31, 2014.

- Supply. The Newcastle gathering system and plant primarily service gas production from the Clareton and Finn-Shurley fields in Weston County, Wyoming. Due to infill drilling and enhanced production techniques, producers have continued to maintain production levels.

- 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 from the Newcastle system is delivered into Black Hills Corporation's MGTC, Inc. ("MGTC") intrastate pipeline, a Hinshaw pipeline that supplies local markets in Wyoming, for transport, distribution and sale.

Southwest Wyoming

Granger gathering system and processing complex

- Customers. For the year ended December 31, 2014, 7% of the Granger complex throughput was from Anadarko and the remaining throughput was from various third-party customers, with the five largest shippers providing 86% of the system throughput.

- Supply. The Granger complex is supplied by the Moxa Arch and the Jonah and Pinedale anticline fields. The Granger gas gathering system had 667 active receipt points as of December 31, 2014.

- Delivery points. The residue from the Granger complex can be delivered to the following major pipelines:

CIG;
Berkshire Hathaway Energy's Kern River pipeline ("Kern River pipeline") and our Mountain Gas Transportation, Inc.'s ("MGTI") pipeline via a connect with Tesoro Logistics LP's ("Tesoro") Rendezvous pipeline ("Rendezvous pipeline");
The Williams Companies, Inc.'s Northwest pipeline ("NWPL"); and
our Overland Trail Transmission, LLC's pipeline ("OTTCO").

The NGLs have market access to Enterprise Products Partners LP's ("Enterprise") Mid-America Pipeline Company pipeline ("MAPL"), which terminates at Mont Belvieu, Texas, as well as to local markets.

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Red Desert gathering system and processing complex

- Customers. For the year ended December 31, 2014, 4% of the Red Desert complex throughput was from Anadarko and the remaining throughput was from various third-party customers, with the six largest producers providing 70% of the system throughput.

- Supply. The Red Desert complex gathers, compresses, treats and processes natural gas and fractionates NGLs produced in the eastern portion of the Greater Green River Basin, providing service primarily to the Red Desert and Washakie Basins.

- Delivery points. Residue from the Red Desert complex is delivered to CIG and WIC, while NGLs are delivered to MAPL, as well as to truck and rail loading facilities.

Rendezvous gathering system

- Customers. Tesoro and Anadarko are the only firm shippers on the Rendezvous gathering system. To the extent capacity on the system is not used by those shippers, it is available to third parties under interruptible agreements.

- Supply and delivery points. The Rendezvous gathering system provides mainline gathering service for gas from the Jonah and Pinedale anticline fields and delivers to our Granger plant, as well as Tesoro’s Blacks Fork gas processing plant, which connects to Questar Pipeline Company’s pipeline (“Questar pipeline”), NWPL and the Kern River pipeline via the Rendezvous pipeline.

Overview - Rocky Mountains - Colorado and Utah

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Location	Asset	Type	Processing / Treating Plants	Processing / Treating Capacity (MMcf/d)	Compressor Stations	Compression Horsepower	Gathering Systems	Pipeline Miles
Colorado	DJ Basin complex (1)	Gathering, Processing & Treating	6	619	21	196,928	2	3,213
Utah	Chipeta (2)	Processing	2	970	—	91,307	—	—
Utah	Clawson	Gathering & Treating	1	40	1	6,310	1	47
Utah	Helper	Gathering & Treating	2	52	2	14,075	1	67
Total			11	1,681	24	308,620	4	3,327

(1) The DJ Basin complex includes the Platte Valley cryogenic processing plant, the Wattenberg gathering system, the Fort Lupton processing plant, the Fort Lupton JT processing plant, the Hambert JT processing plant, the Platteville amine treating plant and the Lancaster plant. Train II of the Lancaster plant is currently under construction and is expected to be completed during the second quarter of 2015.

(2) We are the managing member of and own a 75% interest in Chipeta. Chipeta owns the Chipeta processing complex and the Natural Buttes refrigeration plant.

Rocky Mountains - Colorado

DJ Basin gathering system, treating facility and processing complex

- Customers. For the year ended December 31, 2014, 68% of the DJ Basin complex throughput was from Anadarko and the remaining throughput was from various third-party customers, with the largest providing 21% of the throughput.

- Supply and delivery points. There were 2,881 active receipt points connected to the DJ Basin complex as of December 31, 2014. The DJ Basin complex is primarily supplied by the Wattenberg field, in which Anadarko controls 840,000 gross acres and drilled 369 wells and completed 330 wells during the year ended December 31, 2014.

As of December 31, 2014, the DJ Basin complex had the following delivery points for gas not processed within the DJ Basin complex:

Anadarko’s Wattenberg plant;
DCP Midstream’s (“DCP”) Spindle, Mewbourn and Platteville plants; and
AKA Energy Group, LLC’s Gilcrest plant.

The Anadarko Wattenberg plant and our DJ Basin complex are connected to CIG and Xcel Energy’s residue pipelines. The DJ Basin complex is also connected to the Overland Pass Pipeline Company LLC’s pipeline, DCP’s Wattenberg pipeline and FRP’s pipeline for NGLs. In addition, a truck-loading facility provides access to local NGL markets.

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Rocky Mountains - Utah

Chipeta processing complex

- Customers. Anadarko is the largest customer on the Chipeta system with 82% of the system throughput for the year ended December 31, 2014. The balance of throughput on the system during the year ended December 31, 2014 was from nine third-party customers.

- Supply. The Chipeta system is well positioned to access Anadarko and third-party production in the Uinta Basin where Anadarko controls 245,000 gross acres. Chipeta's inlet is connected to Anadarko's Natural Buttes gathering system, the Questar pipeline and the Three Rivers Gathering, LLC's system, which is owned by Ute Energy and another third party.

- Delivery points. The Chipeta plant delivers NGLs to MAPL, which provides transportation through Enterprise's Seminole pipeline ("Seminole pipeline") and TEP's pipeline in West Texas and ultimately to the NGL fractionation and storage facilities in Mont Belvieu, Texas. The Chipeta plant has natural gas delivery points through the following pipelines:

CIG;
Questar pipeline; and
WIC.

Clawson gathering system and treating facility

- Customers. Anadarko is the largest shipper on the Clawson gathering system with 99% of the total throughput on the system during the year ended December 31, 2014. The remaining throughput on the system was from one third-party producer.

- Supply. The Clawson Springs field covers 7,000 gross acres and produces primarily from the Ferron Coal play.

- Delivery points. The Clawson gathering system delivers into the Questar pipeline. The Questar pipeline 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 United States, primarily California.

Helper gathering system and treating facility

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

- Supply. The Helper and the Cardinal Draw fields are Anadarko-operated coal-bed methane developments on the southwestern edge of the Uinta Basin that produce from the Ferron Coal play. Anadarko owns 19,000 gross acres in each of the Helper and Cardinal Draw fields.

- Delivery points. The Helper gathering system delivers into the Questar pipeline.

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Overview - Mid-Continent and North-central Pennsylvania

Location	Asset	Type	Compressor Stations	Compression Horsepower	Gathering Systems	Pipeline Miles
Southwest Kansas & Oklahoma	Hugoton	Gathering	42	90,214	1	2,067
North-central Pennsylvania	Non-Operated Marcellus (1)	Gathering	4	70,750	2	481
North-central Pennsylvania	Anadarko-Operated Marcellus (2)	Gathering	—	—	3	151
Total			46	160,964	6	2,699

(1) We own a 33.75% interest (the “Non-Operated Marcellus Interest”) in the Liberty and Rome gas gathering systems (the “Non-Operated Marcellus Interest gathering systems”), with a third party as the operator.

(2) We own a 33.75% interest (the “Anadarko-Operated Marcellus Interest”) in the Larry’s Creek, Seely and Warrensville gas gathering systems (the “Anadarko-Operated Marcellus Interest gathering systems”), with Anadarko as the operator.

Southwest Kansas and Oklahoma

Hugoton gathering system

- Customers. Anadarko is the largest customer on the Hugoton gathering system with 86% of the system throughput during the year ended December 31, 2014. Two third-party shippers account for 8% of the system throughput, with the balance from various other third-party shippers.

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- Supply. The Hugoton field continues to be a long-life, low-decline asset for Anadarko, which has an extensive acreage position in the field with 470,000 gross acres. The Hugoton system is well positioned to gather volumes that may be produced from successful new wells drilled by third-party producers.

- Delivery points. The Hugoton gathering system is connected to the Satanta plant, which is owned by Anadarko (49%) and a third party. The Satanta plant processes NGLs and helium, and delivers residue into the Kansas Gas Service's pipeline and Southern Star Central Gas Pipeline, Inc.'s pipeline. The system is also connected to DCP's National Helium Plant, which extracts NGLs and delivers residue into Energy Transfer Partners, LP's ("ETP") Panhandle Eastern Pipe Line.

North-central Pennsylvania

Marcellus gathering systems

- Customers. As of December 31, 2014, there were seven and five priority shippers on the Non-Operated Marcellus Interest gathering systems and the Anadarko-Operated Marcellus Interest gathering systems, respectively, including Anadarko. For the year ended December 31, 2014, Anadarko represented 21% and 36% of throughput on the Non-Operated Marcellus Interest gathering systems and the Anadarko-Operated Marcellus Interest gathering systems, respectively. Capacity not used by priority shippers is available to third parties.

- Supply and delivery points. As of December 31, 2014, Anadarko had a working interest in over 722,000 gross acres within the Marcellus shale. The Non-Operated Marcellus Interest gathering systems have access to Transcontinental Gas Pipeline Company, LLC's pipeline ("TRANSCO"), Tennessee Gas Pipeline Company, LLC's pipeline and Millennium Pipeline Company, LLC's pipeline. The Anadarko-Operated Marcellus Interest gathering systems have access to TRANSCO.

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Overview - Texas

Location	Asset	Type	Processing / Treating Plants	Processing / Treating Capacity (MMcf/d)	Processing Capacity (MBbls/d)	Compressor Stations	Compression Horsepower	Gathering Systems	Pipeline Miles
East Texas	Dew	Gathering	—	—	—	9	36,085	1	324
East Texas	Pinnacle (1)	Gathering & Treating	1	500	—	1	1,340	1	270
East Texas	Mont Belvieu JV (2)	Processing	2	—	170	—	—	—	—
South Texas	Brasada complex (3)	Gathering, Processing & Treating	2	200	—	—	—	1	71
West Texas	Haley	Gathering	—	—	—	—	—	1	142
West Texas	DBM complex (4)	Gathering, Processing & Treating	3	300	—	4	23,575	1	253
Total			8	1,000	170	14	61,000	5	1,060

(1) The Pinnacle system includes the Bethel treating facility.
(2) We own a 25% interest in the Mont Belvieu JV, which owns two NGL fractionation trains. A third party serves as the operator.
(3) The table above excludes 15MBbls/d of condensate stabilization capacity at the Brasada complex.
(4) The table above excludes 1,800 gpm of amine treating capacity at the DBM complex.

East and South Texas

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East Texas

Dew gathering system

- Customers. Anadarko is the largest shipper on the Dew gathering system with 99% of the total throughput on the system during the year ended December 31, 2014. The remaining throughput on the system was from two third-party producers.

- Supply. As of December 31, 2014, Anadarko had 794 producing wells in the Bossier play and controlled 111,000 gross acres in the area.

- Delivery points. The Dew gathering system has delivery points on Kinder Morgan, Inc.'s Tejas pipeline ("Tejas pipeline") and with Pinnacle, which is the primary delivery point and is described in more detail below.

Pinnacle gathering system and treating facility

- Customers. Anadarko is the largest shipper on the Pinnacle gathering system with 92% of system throughput for the year ended December 31, 2014. The remaining throughput on the system during that period was from five third-party shippers.

- Supply. The Pinnacle gathering system is well positioned to provide sour gas gathering and treating services to the five-county area over which it extends, including the Cotton Valley Lime and Reef formations, which contain relatively high concentrations of hydrogen sulfide and carbon dioxide.

- Delivery points. The Pinnacle gathering system is connected to the following pipelines:

Atmos Energy's Texas pipeline;
Midcoast Energy Partners, LP's East Texas system;
Energy Transfer Fuels' pipeline;
Enterprise Texas Pipeline, LP's pipeline;
ETC Texas Pipeline, Ltd's pipeline; and
the Tejas pipeline.

These pipelines provide transportation to the Carthage, Waha and Houston Ship Channel market hubs in Texas.

Mont Belvieu JV fractionation trains

- Customers. The Mont Belvieu JV does not directly contract with customers, but rather is allocated volumes from Enterprise based on the available capacity of the other trains at Enterprise's NGL fractionation complex in Mont Belvieu, Texas.

- Supply and delivery points. Enterprise receives volumes at its fractionation complex in Mont Belvieu, Texas via a large number of pipelines that terminate there, including the Seminole pipeline, Skelly-Belvieu Pipeline Company, LLC's pipeline and TEP. Individual NGLs are delivered to end users either through customer-owned pipelines that are connected to nearby petrochemical plants or via export terminal.

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South Texas

Brasada gathering system, stabilization facility and processing complex

- Customers. Anadarko provides 100% of the throughput to the Brasada complex. Anadarko delivers gas and condensate to the plant on behalf of itself and its upstream partners.

- Supply. Supply of gas and NGLs for the facility comes from Anadarko’s production in the Eagleford shale, in which Anadarko controls 416,000 gross acres.

- Delivery points. The facility delivers residue gas into the Eagle Ford Midstream system operated by NET Midstream, LLC. It delivers the NGLs into the South Texas NGL Pipeline System operated by Enterprise.

West Texas

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Haley gathering system

- Customers. Anadarko’s production represented 68% of the Haley gathering system’s throughput for the year ended December 31, 2014. The remaining throughput was attributable to one third-party producer.

- Supply. As of December 31, 2014, Anadarko had access to 445,000 gross acres in the greater Delaware Basin, 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 Kinder Morgan, Inc.’s El Paso Natural Gas pipeline (“El Paso pipeline”) or Enterprise GC, LLC’s pipeline for ultimate delivery into ETP’s Oasis pipeline (“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.

DBM gathering system, treating facility and processing complex. The DBM complex includes 300 MMcf/d of cryogenic processing capacity, 1,800 gpm of amine treating capacity and a 253-mile rich gas gathering system, which has both high and low pressure segments.

- Customers. Gas gathered and processed through the DBM complex is primarily from nine third party producers, with the three largest producers providing 77% of the system throughput for the year ended December 31, 2014.

- Supply. Supply of gas and NGLs for the complex comes from production from the Delaware Sands, Avalon Shale, Bone Springs and Wolfcamp formations in the Delaware Basin portion of the Permian Basin. Anadarko currently holds 445,000 gross acres within the Delaware Basin.

- Delivery points. Residue gas produced at the facility is delivered to an interconnect with the El Paso pipeline. NGL production is delivered to an interconnect with DCP’s Sand Hills pipeline. As of December 31, 2014, there was an additional NGL interconnect under construction at our DBM complex with an expected in-service date during the first quarter of 2015.

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TRANSPORTATION

Overview

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Location	Asset	Type	Compressor Stations	Operational Horsepower	Pipeline Miles
Northeast Wyoming	MIGC (1)	Gas	10	24,828	262
Southwest Wyoming	OTTCO	Gas	1	3,174	217
Utah	GNB NGL (1)	NGL	—	—	32
Colorado, Kansas, Oklahoma	White Cliffs (1) (2)	Oil	—	—	526
Colorado, Oklahoma, Texas	FRP (1) (3)	NGL	1	7,500	435
Texas, Oklahoma	TEG	NGL	6	1,895	117
Texas	TEP (1) (3)	NGL	1	25,000	593
Total			19	62,397	2,182

(1) MIGC, GNB NGL, White Cliffs, FRP and TEP are regulated by the Federal Energy Regulatory Commission ("FERC").
(2) We own a 10% interest in the White Cliffs pipeline, which is operated by a third party.
(3) We own a 20% interest in TEG and TEP and a 33.33% interest in FRP. All three systems are operated by third parties.

Rocky Mountains - Northeast Wyoming

MIGC transportation system

- Customers. Anadarko is the largest firm shipper on the MIGC system, with 87% of throughput for the year ended December 31, 2014. The remaining throughput on the MIGC system was from 17 third-party shippers. MIGC offers both forward-haul and backhaul transportation services and is certificated for 175 MMcf/d of firm transportation capacity.

- Supply. As of December 31, 2014, Anadarko had a working interest in over 1.1 million gross acres within the Powder River Basin. Anadarko's gross acreage includes substantial undeveloped acreage positions in the Big George coal play and the multiple seam coal fairway to the north of the Big George coal play. MIGC receives gas from various coal-bed methane gathering systems throughout the Powder River Basin and the Hilight system, as well as from WBI Energy Transmission, Inc. on the north end of the transportation system.

- Delivery points. MIGC volumes can be redelivered to the hub in Glenrock, Wyoming, which has access to the following interstate pipelines:

CIG;
TIGT; and
WIC.

Volumes can also be delivered to MGTC.

Rocky Mountains - Southwest Wyoming

OTTCO transportation system

- Customers. For the year ended December 31, 2014, 12% of OTTCO's throughput was from Anadarko. The remaining throughput on the OTTCO transportation system was from two third-party shippers. Revenues on the OTTCO transportation system are generated from contract demand charges and volumetric fees paid by shippers under firm and interruptible gas transportation agreements. Most of OTTCO's gas transportation agreements are month-to-month with the remainder generally having terms of less than one year. OTTCO has one current third-party firm transportation agreement for 21 MMBtu/d, which extends through December 2021.

Supply and delivery points. Supply points to the OTTCO transportation system include the Granger complex and ExxonMobil Corporation's Shute Creek plant, which are supplied by the eastern portion of the Greater Green River Basin, the Moxa Arch and the Jonah and Pinedale anticline fields. Primary delivery points include the Red Desert complex, two third-party industrial facilities and an interconnection with Kern River pipeline.

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Rocky Mountains - Utah

GNB NGL pipeline

- Customers. Anadarko was the only shipper on the GNB NGL pipeline for the year ended December 31, 2014.

- Supply. The GNB NGL pipeline receives NGLs from Chipeta's gas processing facility and Tesoro's Stagecoach/Iron Horse gas processing complex.

- Delivery points. The GNB NGL pipeline delivers NGLs to MAPL, which provides transportation through the Seminole pipeline and TEP in West Texas, and ultimately to NGL fractionation and storage facilities in Mont Belvieu, Texas.

Rocky Mountains - Colorado

White Cliffs pipeline

- Customers. The White Cliffs pipeline had multiple committed shippers, including Anadarko, during the year ended December 31, 2014. In addition, other parties may ship on the White Cliffs pipeline at FERC-based rates. The White Cliffs dual pipeline system provides 150 MBbls/d of crude takeaway capacity from Platteville, Colorado to Cushing, Oklahoma. White Cliffs is currently undergoing an expansion project that will increase the pipeline's capacity to over 200 MBbls/d. These expansion projects are scheduled to be completed in mid-to-late 2015.

- Supply. The White Cliffs pipeline is supplied by production from the DJ Basin and offers the only direct route from the DJ Basin to Cushing, Oklahoma.

- 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 Gulf Coast and mid-continent refineries. At the point of origin, it has a 300,000-barrel storage facility adjacent to a truck-unloading facility.

Texas

TEFR Interests

- Front Range Pipeline. FRP provides takeaway capacity from the DJ Basin in Northeast Colorado. FRP has injection points from gas plants in Weld County, Colorado (including our Lancaster plant), which is part of the DJ Basin complex (see Rocky Mountains—Colorado and Utah within these Items 1 and 2). FRP connects to TEP near Skellytown, Texas. During the year ended December 31, 2014, FRP had two committed shippers, including Anadarko and provides capacity for other shippers at the posted FERC tariff rate.

- Texas Express Gathering. TEG consists of two NGL gathering systems that provide plants in North Texas, the Texas panhandle and West Oklahoma with access to NGL takeaway capacity on TEP. TEG had one committed shipper during the year ended December 31, 2014.

- Texas Express Pipeline. TEP delivers to NGL fractionation and storage facilities in Mont Belvieu, Texas. At Skellytown, Texas, TEP is supplied with NGLs from other pipelines including FRP and MAPL. TEP had multiple committed shippers, including Anadarko, during the year ended December 31, 2014 and provides capacity for other shippers at the posted FERC tariff rates.

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Assets Under Development

We currently have the following significant projects scheduled for completion in 2015 and 2016.

- Lancaster Train II in the DJ Basin: We are currently constructing the second train of the Lancaster plant, which is part of the DJ Basin complex. The second train is designed to have a capacity of 300 MMcf/d and is expected to begin service during the second quarter of 2015. Anadarko has agreed to a fee-based contract with a 10-year throughput guarantee of 200 MMcf/d, which will begin on the plant's in-service date.

- DBM Trains IV and V in West Texas: We are currently preparing for the construction of an additional cryogenic unit at our DBM complex with 200 MMcf/d of designed processing capacity and an in-service date expected during the first quarter of 2016. We have also made progress payments towards the construction of another cryogenic unit at our DBM complex (Train V), with an expected in-service date of mid-2016.

COMPETITION

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. However, a substantial portion of our throughput volumes on a majority of our systems are owned or controlled by Anadarko. In addition, Anadarko has dedicated future production to us from its acreage surrounding the Wattenberg, Dew, Pinnacle, Haley, Helper, Clawson and Hugoton gathering systems. We believe that our assets that are located outside of the dedicated areas are geographically well positioned to retain and attract third-party volumes due to our competitive rates.
We believe the primary advantages of our assets are their proximity to established and/or future production, and the service flexibility they provide 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.

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Gathering Systems and Processing Plants

The following table summarizes the primary competitors for our gathering systems and processing plants at December 31, 2014.

System	Competitor(s)
Anadarko-Operated Marcellus Interest gathering systems	Regency Energy Partners LP (formerly PVR Midstream) and National Fuel Gas Midstream Corporation
Bison treating facility	Thunder Creek Gas Services, LLC and Fort Union (treating only)
Brasada gathering system, stabilization facility and processing complex	Enterprise, ETP and Kinder Morgan, Inc.
Chipeta processing complex	Tesoro and Kinder Morgan, Inc.
Dew and Pinnacle gathering systems and Pinnacle treating facility	ETC Texas Pipeline, Ltd., Midcoast Energy Partners, LP (East Texas), XTO Energy and the Tejas pipeline
DJ Basin gathering system, treating facility and processing complex	DCP and AKA Energy Group, LLC
Fort Union gathering system and treating facility	Bison treating facility (carbon dioxide treating services only), MIGC, Thunder Creek Gas Services, LLC and TransCanada Corporation
Granger gathering system and processing complex	Williams Field Services, Enterprise/Jonah Gas Gathering Company and Tesoro
Haley gathering system	Anadarko's Delaware Basin Joint Venture, Enterprise GC, LP, Regency Gas Services, LP and Targa Midstream Services, LP
Helper and Clawson gathering systems and treating facilities	XTO Energy
Hilight gathering system and processing plant	DCP, ONEOK Gas Gathering Company, Thunder Creek Gas Services, LLC, Crestwood-Access, Tallgrass Energy Partners, LP and Rowdy Gathering Company
Hugoton gathering system	ONEOK Gas Gathering Company, DCP and Linn Energy
Mont Belvieu JV fractionation trains	Targa Resources LP, Phillips 66, Lone Star NGL LLC and ONEOK Partners, LP
Newcastle gathering system and processing plant	DCP
Non-Operated Marcellus Interest gathering systems	Regency Energy Partners, LP (formerly PVR Midstream)
DBM gathering system, treating facility and processing complex	Anadarko's Delaware Basin Joint Venture, Regency Gas Services, Enterprise GC, LP and Targa Midstream, LP
Red Desert gathering system and processing complex	Williams Field Services and Tesoro
Rendezvous gathering system	No significant direct competition

Transportation

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, LLC, TransCanada Corporation's Bison pipeline, which commenced operations in January 2011, and the Fort Union gathering system. The White Cliffs pipeline and the OTTCO transportation system face no direct competition from other pipelines, although White Cliffs pipeline shippers could sell crude oil in local markets or ship crude via rail services rather than via pipeline to Cushing, Oklahoma. The TEFR interests compete with DCP's Sand Hills pipeline, West Texas LPG Pipeline LP's pipeline and the Seminole pipeline.

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REGULATION OF OPERATIONS

Safety and Maintenance

Many of the pipelines we use to gather and transport natural gas and NGLs are subject to regulation by the Pipeline and Hazardous Materials Safety Administration (“PHMSA”) of the Department of Transportation (the “DOT”) pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended (the “NGPSA”), with respect to natural gas and the Hazardous Liquids Pipeline Safety Act of 1979, as amended (the “HLPSA”), with respect to NGLs. Both the NGPSA and the HLPSA were amended by the Pipeline Safety Improvement Act of 2002 (the “PSI Act”) and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (the “PIPES Act”). Pursuant to these acts, PHMSA has promulgated regulations governing, among other things, pipeline wall thicknesses, design pressures, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Additionally, PHMSA has promulgated regulations requiring pipeline operators to develop and implement integrity management programs for certain gas and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect “high consequence areas,” where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources and unusually sensitive ecological areas. We believe that our pipeline operations are in substantial compliance with applicable NGPSA and HLPSA requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance with the NGPSA and HLPSA could result in increased costs.

These pipeline safety laws were amended in January 2012, when President Obama signed the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (the “2011 Pipeline Safety Act”), which requires increased safety measures for gas and hazardous liquids pipelines. Among other things, the 2011 Pipeline Safety Act directed the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, pipeline material strength testing, verification of the maximum allowable pressure of certain pipelines, and operator verification of records confirming the maximum allowable pressure of certain intrastate gas transmissions pipelines. The 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day of violation and from $1.0 million to $2.0 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any implementation of PHMSA regulations thereunder could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any of which could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position.

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In addition, while states are largely preempted by federal law from regulating pipeline safety for interstate lines, most are certified by PHMSA 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 or material cost in complying with applicable intrastate pipeline safety laws and regulations in 2015. Our pipelines have operations and maintenance plans designed to keep the facilities in compliance with pipeline safety requirements. We, or the entities in which we own an interest, inspect our pipelines regularly in substantial compliance with applicable state and federal maintenance requirements. Nonetheless, the adoption of new or amended regulations by PHMSA or the states in which we operate that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on us and similarly situated midstream operators. For instance, in August 2011, PHMSA published an advance notice of proposed rulemaking in which the agency was seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revising the definitions of "high consequence areas" and "gathering lines" and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. Most recently, in response to an August 2014 report from the U.S. Government Accountability Office (the "GAO"), PHMSA stated that it is developing revisions to its pipeline safety regulations, including consideration of the need to adopt safety requirements for gas gathering pipelines that are not currently subject to regulation.

We are also subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended ("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. The OSHA hazard communication standard, the community right-to-know regulations of the U.S. Environmental Protection Agency (the "EPA") 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's Process Safety Management ("PSM") regulations as well as EPA's Risk Management Program ("RMP") regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above specified thresholds or any process which involves flammable liquid or gas in excess of 10,000 pounds. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety. However, notwithstanding the applicability of these PSM and RMP requirements at regulated facilities, PHMSA and one or more state regulators, including the Texas Railroad Commission, have in the past expanded the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities, in order to assess compliance of such equipment and pipelines with hazardous liquid pipeline safety requirements. These actions by PHMSA are currently subject to judicial and administrative challenges by one or more midstream operators; however, to the extent that such legal challenges are unsuccessful, midstream operators of NGL fractionation facilities and associated storage facilities subject to such inspection may be required to make operational changes or modifications at their facilities to meet standards beyond current PSM and RMP requirements, which changes or modifications may result in additional capital costs, possible operational delays and increased costs of operation that, in some instances, may be significant.

Interstate Natural Gas Pipeline Regulation

Regulation of pipeline transportation services may affect certain aspects of our business and the market for our products and services.

The operation of our MIGC pipeline and the natural gas residue pipeline at the tailgate of the DBM complex (the "DBM pipeline") are subject to regulation by FERC under the Natural Gas Act of 1938 (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;
- types of services that may be offered to customers;

- certification and construction of new facilities;
- acquisition, extension, disposition or abandonment of facilities;
- maintenance of accounts and records;
- internet posting requirements for available capacity, discounts and other matters;
- pipeline segmentation to allow multiple simultaneous shipments under the same contract;
- capacity release to create a secondary market for transportation services;
- relationships between affiliated companies involved in certain aspects of the natural gas business;
- 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 or by action of FERC under Section 5 of the NGA, and proposed rate increases may be challenged by protest. The outcome of any successful complaint or protest against our rates could have an adverse impact on revenues associated with providing transportation service. For example, one such matter relates to FERC's policy regarding allowances for income taxes in determining a regulated entity's cost of service. FERC allows regulated companies to recover an allowance for income taxes in rates only to the extent the company or its owners, such as our unitholders, are subject to U.S. income tax. This policy affects whom we allow to own our units, and if we are not successful in limiting ownership of our units to persons or entities subject to U.S. income tax, the rates and revenues for our FERC-regulated pipelines could be adversely affected.

Interstate natural gas pipelines regulated by FERC are required to comply with numerous regulations related to standards of conduct, market transparency, and market manipulation. FERC's standards of conduct regulate the manner in which interstate natural gas pipelines may interact with their marketing affiliates (unless FERC has granted a waiver of such standards). FERC's market oversight and transparency regulations require annual reports of purchases or sales of natural gas meeting certain thresholds and criteria and certain public postings of information on scheduled volumes. FERC's market manipulation regulations promulgated pursuant to the Energy Policy Act of 2005 (the "EPAct 2005") 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 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 EPAct 2005 also amends the NGA and the Natural Gas Policy Act of 1978 (the "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. Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

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Interstate Liquids Pipeline Regulation

Regulation of interstate liquids pipeline services may affect certain aspects of our business and the market for our products and services.

Our NGL pipelines with FERC tariffs on file provide service as common carriers under the Interstate Commerce Act, the Energy Policy Act of 1992, and related rules and orders. FERC regulation requires that interstate liquid pipeline rates, including rates for transportation of NGLs, be filed with FERC and that these rates be “just and reasonable” and not unduly discriminatory. Rates of interstate NGL pipelines are currently regulated by FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning in 2010, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 2.65%. This adjustment is subject to review every five years. Under FERC’s regulations, an NGL pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology.

The Interstate Commerce Act permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rate during the term of the investigation. The just and reasonable rate used to calculate refunds cannot be lower than the last tariff rate approved as just and reasonable. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for charges in excess of a just and reasonable rate for a period of up to two years prior to the filing of a complaint.

Natural Gas Gathering Pipeline Regulation

Regulation of gathering pipeline services may affect certain aspects of our business and the market for our products and services. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. We believe that our natural gas pipelines meet the traditional tests that FERC has used to determine that a pipeline is a gathering pipeline and is, therefore, not subject to FERC jurisdiction, although FERC has not made any determinations with respect to the jurisdictional status of any of our pipelines other than MIGC and the DBM pipeline. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial 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. FERC makes jurisdictional determinations on a case-by-case basis. In recent years, FERC has regulated the gathering activities of interstate pipeline transmission companies more lightly, 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.

FERC’s anti-manipulation rules apply to 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. In addition, FERC’s market oversight and transparency regulations may also apply to otherwise non-jurisdictional entities to the extent annual purchases and sales of natural gas reach a certain threshold. As noted above, FERC’s civil penalty authority under EPAct 2005 would apply to violations of these rules.

Intrastate Pipeline Regulation

Regulation of intrastate pipeline services may affect certain aspects of our business and the market for our products and services. Intrastate natural gas and liquids transportation is subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate shippers within the state on a comparable basis, we believe that the regulation of intrastate transportation in any states in which we operate will not disproportionately affect our operations. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of the products that we produce, as well as the revenues we receive for sales of such products.

In the event any of our intrastate pipelines offer natural gas transportation services under Section 311 of the NGPA, such pipelines will be required to meet certain quarterly reporting requirements providing detailed transaction information which could be made public. Such pipelines will also be subject to periodic rate review by FERC. In addition, FERC’s anti-manipulation, market oversight, and market transparency regulations may extend to intrastate natural gas pipelines although they may otherwise be non-jurisdictional, and FERC’s civil penalty authority under EPAct 2005 would apply to violations of these rules.

Financial Reform Legislation

For a description of financial reform legislation that may affect our business, financial condition and results of operations, please read Risk Factors under Item 1A of this Form 10-K for more information.

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ENVIRONMENTAL MATTERS

General

Our operations are subject to stringent federal, tribal, state and local laws and regulations relating to the protection of the environment. These laws and regulations can restrict or impact our business activities in many ways, such as requiring the acquisition of permits to conduct regulated activities; restricting the way we emit, discharge or dispose of our wastes; limiting or prohibiting construction activities in sensitive areas, such as wetlands and other protected areas; requiring remedial actions to mitigate pollution from former and current operations; and imposing substantial liabilities for pollution resulting from our operations. Failure to comply with these requirements may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders enjoining performance of some or all of our operations. Also, certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where hydrocarbons or wastes have been disposed or released. Our operations and construction activities are also subject to state and local ordinances that require us to take curative actions to reduce or mitigate nuisance-type conditions such as excessive levels of dust or noise or increased traffic congestion.

We have implemented programs and policies designed to keep our pipelines, plants and other facilities in substantial compliance with environmental laws and regulations. The trend in environmental regulation is to place more restrictions 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 significantly in excess of the amounts we currently anticipate. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with existing requirements will not materially affect us, there is no assurance that the current conditions will continue in the future or that such future compliance will not have a material adverse effect on our business, financial conditions or results of operations.

Below is a discussion of several of the material environmental laws and regulations, as amended from time to time, that relate to our business.

Hazardous Substances and Wastes

The federal Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where a release of hazardous substances occurred and companies that disposed or arranged for the disposal of the hazardous substances released at the site. Under CERCLA, these "responsible persons" may be subject to strict and joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. We generate materials in the course of our ordinary operations that are regulated as "hazardous substances" under CERCLA or similar state laws.

We also generate non-hazardous and hazardous wastes that are subject to the requirements of the federal Resource Conservation and Recovery Act (the "RCRA") and comparable state statutes. While the RCRA regulates both non-hazardous and hazardous wastes, it imposes more stringent requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the ordinary course of our operations and our customer's operations, wastes are generated constituting non-hazardous waste and, in some instances, hazardous wastes.

We own or lease properties where petroleum hydrocarbons are being or have been handled for many years. We have generally used operating and disposal practices that were standard in the industry at the time, although petroleum hydrocarbons or 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 wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws.

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Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission 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 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. For example, in December 2014, the EPA published proposed regulations to revise the National Ambient Air Quality Standard (the “NAAQS”) for ozone, recommending a standard between 65 to 70 parts per billion (“ppb”) for both the 8-hour primary and secondary standards, protective of public health and public welfare, respectively. The current primary and secondary ozone standards are each set at 75 ppb. In June 2014, the Clear Air Scientific Advisory Committee concluded that scientific evidence supported a standard between 60 to 70 ppb. Ultimately, the EPA decided to propose a new standard between 65 and 70 ppb, but is taking comment on whether a 60 ppb standard should be established for the primary standard or whether the existing 75 ppb standard should be retained. Compliance with existing and potential regulatory requirements, such as the proposed lowering of the ozone standard, may require modifications to certain operations, including the installation of new emission controls on our surface equipment that could result in longer permitting timelines, as well as a significantly increase in our operational costs, including increased capital expenditures and operation costs, which could adversely impact our business. The EPA expects to issue a final rule by October 1, 2015.

Climate Change

The EPA has adopted regulations under the Clean Air Act that, among other things, establish construction and operating permit reviews for greenhouse gas (“GHG”) emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain operating permits for their GHG emissions are required to meet best available control technology standards that typically are established by the states. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States including, among others, onshore processing, transmission, storage and distribution facilities. On December 9, 2014, the EPA published a proposed rule that would expand the petroleum and natural gas system sources for which annual GHG emissions reporting is currently required to include certain onshore gathering and boosting systems consisting primarily of gathering pipelines, compressors and process equipment used to perform natural gas compression, dehydration and acid gas removal. We are monitoring GHG emissions from our facilities in accordance with current GHG emissions reporting requirements in a manner that we believe is in substantial compliance with applicable reporting obligations and are currently assessing the potential impact that the December 9, 2014 proposed rule may have on our future reporting obligations, should the proposal be adopted.

In January 2015, the Obama Administration announced plans to reduce GHGs by regulating methane emissions from the oil and natural gas sector. The Obama Administration stated that they will seek to reduce methane emissions in the oil and natural gas sector by 40 to 45 percent from 2012 levels by 2025. There are a number of elements involved in the plan, including efforts by the EPA, the DOT and the Department of the Interior. As to the EPA, the Obama Administration announced that the EPA will propose new source rules for methane this summer and seek to finalize them in 2016.

Also, Congress has from time to time considered legislation to reduce emissions of GHGs and a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. The adoption of any legislation or regulation that requires reporting of GHGs or otherwise restricts emissions of GHGs from our or our customers' equipment and operations could require us or our customers to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for our services.

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Water Discharges

The federal Water Pollution Control Act (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 United States and adjacent wetlands. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of permits issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure requirements under 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. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance.
The federal Oil Pollution Act of 1990 (the "OPA") which amends the Clean Water Act, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the United States. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes, among others, owners and operators of onshore facilities, such as our plants and pipelines.

Hydraulic Fracturing

Although we do not directly engage in hydraulic fracturing, our customers do conduct such activities. Hydraulic fracturing is an important and increasingly common practice that is used to stimulate production of natural gas and/or oil from low permeability hydrocarbon bearing subsurface rock formations. Hydraulic fracturing is typically regulated by state oil and gas commissions and similar agencies but several federal agencies have asserted regulatory authority over aspects of the process, including the EPA and the federal Bureau of Land Management ("BLM"). From time to time, the U.S. Congress has considered legislation to provide for federal regulation of hydraulic fracturing, but in the absence of any laws adopted by Congress, a growing number of states, including those in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations. In addition, in December 2014, the state of New York prohibited hydraulic fracturing altogether. Also, local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Further, several federal governmental agencies are conducting reviews and studies on the environmental aspects of hydraulic fracturing, including the EPA, which is planning to issue a draft of its final report on hydraulic fracturing in the first half of 2015. The results of such review or studies could spur initiatives to further regulate hydraulic fracturing. The adoption of new laws or regulations at the federal, state or local levels imposing more stringent restrictions on hydraulic fracturing could make it more difficult for our customers to complete wells, increase our customers' costs of compliance and doing business, and otherwise adversely affect the hydraulic fracturing services they perform, which could negatively impact demand for our gathering and processing services.

Endangered Species Considerations

The Endangered Species Act (the "ESA") restricts activities that may affect endangered or threatened species or their habitats. Similar protections are offered for migratory birds under the Migratory Bird Treaty Act. If endangered species are located in areas of the underlying properties where we wish to conduct development activities, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to review and consider the listing of numerous species as endangered under the ESA by no later than the completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where we or our oil and natural gas exploration and production customers operate could cause us or our customers to incur increased costs arising from species protection measures and could result in delays or limitations in our customers' performance of operations, which could reduce demand for our midstream services.

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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 or affiliates of ours 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, 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, 2014, Anadarko employed 360 people who provided direct support to our field operations. All of the employees required to conduct and support our operations are employed by Anadarko and are covered either under a services and secondment or omnibus 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 statements by management, forward-looking statements concerning our operations, economic performance and financial condition. These forward-looking statements include statements preceded by, followed by or that otherwise include the words "believes," "expects," "anticipates," "intends," "estimates," "projects," "target," "goal," "plans," "objective," similar expressions or variations on such expressions. These statements discuss future expectations, contain projections of results of operations or financial condition or include other "forward-looking" information. Although we and our general partner believe that the expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any 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:

- our ability to pay distributions to our unitholders;
- our and Anadarko's assumptions about the energy market;
- future throughput, including Anadarko's production, which is gathered or processed by or transported through our assets;
- our 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, demand for, and the price of, oil, natural gas, NGLs and related products or services;
- weather and natural disasters;
- inflation;
- the availability of goods and services;
- general economic conditions, either internationally or domestically or in the jurisdictions in which we are doing business;
- federal, state and local laws, including those that limit Anadarko and other producers' hydraulic fracturing or other oil and natural gas operations;
- environmental liabilities;
- legislative or regulatory changes, including changes affecting our status as a partnership for federal income tax purposes;

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- changes in the financial or operational condition of Anadarko;
- changes in Anadarko's capital program, strategy or desired areas of focus;
- our commitments to capital projects;
- our ability to use our RCF;
- the creditworthiness of Anadarko or our other counterparties, including financial institutions, operating partners and other parties;
- our ability to repay debt;
- our ability to mitigate a substantial majority of the commodity price risks inherent in our percent-of-proceeds and keep-whole contracts;
- conflicts of interest among us, our general partner, WGP and its general partner, and affiliates, including Anadarko;
- 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;
- the timing, amount and terms of future issuances of equity and debt securities; and
- other factors discussed below and elsewhere in this Item 1A, under the caption Critical Accounting Policies and Estimates included under Item 7 of this Form 10-K, and in our other public filings and press releases.

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

Common 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 Form 10-K 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 INHERENT IN 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 that is gathered, treated, 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, 2014, 48% of our total gathering, transportation and treating throughput (excluding equity investment throughput and throughput measured in barrels) was comprised of natural gas production owned or controlled by Anadarko. For the year ended December 31, 2014, 57% of our total processing throughput (excluding equity investment throughput and throughput measured in barrels) was attributable to natural gas production owned or controlled by Anadarko. 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 pursuant to the terms of our applicable gathering agreements. 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 systems and a material decline in our revenues and cash available for distribution.

Because we are substantially dependent on Anadarko as our primary customer and the ultimate owner of our general partner, any development that materially and adversely affects Anadarko's operations, financial condition or 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 or increase the costs of our borrowings.

We are substantially dependent on Anadarko as our primary customer and the ultimate parent of our general partner and we 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 Anadarko's 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 Anadarko's exploration and development activities;
- a reduction in or reallocation of Anadarko's capital budget, which could reduce the gathering, transportation and treating volumes available to us as a midstream operator, limit our midstream opportunities for organic growth or limit the inventory of midstream assets we may acquire from Anadarko;
- Anadarko's ability to replace reserves;
- Anadarko's operations in foreign countries, which are subject to political, economic and other uncertainties;
- Anadarko's drilling and operating risks, including potential environmental liabilities;
- transportation capacity constraints and interruptions;
- adverse effects of governmental and environmental regulation; and

- adverse effects from current 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 from Anadarko 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 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 or other terms of any capital markets transactions, may be adversely affected by any impairments to Anadarko’s financial condition or adverse changes in its credit ratings.

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 Form 10-K for the year ended December 31, 2014 (which is not, and shall not be deemed to be, incorporated by reference herein), for a full discussion of the risks associated with Anadarko’s business.

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

Sustained low natural gas, NGL or crude oil prices impact natural gas and oil exploration and production activity levels and can result in a decline in the production of hydrocarbons over the medium to long term, resulting in reduced throughput on our systems. Such a decline also potentially affects the ability of our vendors, suppliers and customers to continue operations. As a result, sustained lower natural gas and crude oil prices could have a material adverse effect on our business, results of operations, financial condition and our ability to pay 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, market prices for natural gas declined substantially from the highs achieved in 2008 and have remained depressed for several years. More recently, uncertain global demand and the increased supply resulting from the rapid development of shale plays throughout North America has contributed significantly to a substantial drop in crude oil prices. For example, daily settlement prices for New York Mercantile Exchange (“NYMEX”) West Texas Intermediate crude oil ranged from a high of $107.26 per barrel to a low of $53.27 per barrel during 2014. Daily settlement prices for NYMEX Henry Hub natural gas ranged from a high of $6.15 per MMBtu to a low of $2.89 per MMBtu during 2014. Additional factors impacting commodity prices include the following:

- domestic and worldwide economic and geopolitical conditions;
- weather conditions and seasonal trends;
- the ability to develop recently discovered fields or deploy new technologies to existing 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 (“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 forecasted supply and demand for, and prices of, natural gas, NGLs and other commodities.

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, among other things, 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 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. 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 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 have had a negative impact on natural gas 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 units.

In order to pay the announced fourth quarter 2014 distribution of $0.70 per unit per quarter, or $2.80 per unit per year, we will require available cash of $126.0 million per quarter, or $504.2 million per year, based on the number of common units, general partner units and IDRs outstanding at February 2, 2015. 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;
- 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.

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

- our level of capital expenditures;

- our level of operating and maintenance and general and administrative costs;

- our debt service requirements and other liabilities;

- fluctuations in our working capital needs;

- our ability to borrow funds and access capital markets;

- our treatment as a flow-through entity for U.S. federal income tax purposes;

- restrictions contained in debt agreements to which we are a party; and

- the amount of cash reserves established by our general partner.

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.

For the year ended December 31, 2014, 20% of our gross margin was generated under percent-of-proceeds and keep-whole arrangements pursuant to which the associated revenues and expenses are directly correlated with the prices of natural gas, condensate and NGLs. This percentage may significantly increase as a result of future acquisitions, if any.

We pursue various strategies to seek to reduce our exposure to adverse changes in the prices for natural gas, 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 commodity price swap agreements with Anadarko expiring at various times through December 2016 to manage a substantial majority of 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 commodity price swap agreements, we may be prevented from realizing the full benefits of price increases above the levels set in those agreements. In addition, our commodity price management may expose us to the risk of financial loss in certain circumstances, including if the counterparties to our hedging or other price risk management contracts fail to perform under those arrangements.

On December 31, 2014, our commodity price swap agreements for the Hilight and Newcastle systems and the Granger complex expired without renewal. On June 30, 2015, and September 30, 2015, our commodity price swap agreements for the DJ Basin complex and Hugoton system, respectively, will expire. We may be unable to renew such agreements with Anadarko on similar terms or at all. If such agreements are renewed with Anadarko, they may be renewed at lower prices than those established in the agreements currently in place. In the event that we are unable to renew agreements with Anadarko, we may seek to enter into third-party commodity price swap agreements or similar hedging arrangements. Any such market based hedging arrangement may be less favorable from a commodity pricing perspective and would likely expose us to volumetric risk to which we are currently not exposed, because our current commodity price swap agreements with Anadarko are based on our actual volumes.

Additionally, if we are unable to effectively manage the risk associated with our contracts that have commodity price exposure, 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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Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs, operating restrictions or delays in the completion of oil and gas wells, which could decrease the need for our gathering and processing services.

While we do not conduct hydraulic fracturing, our customers do conduct such activities. The U.S. Congress has, from time to time, considered legislation to provide for federal regulation of hydraulic fracturing, but while the Congress has not adopted any such laws in recent years, several federal agencies, including the EPA and the BLM, have asserted regulatory authority over aspects of the process. In addition, a growing number of states, including those in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations. Moreover, more stringent regulation of hydraulic fracturing may occur at the local level, resulting in the need to comply with local measures in addition to regulations typically imposed by state oil and gas commissions and similar agencies. If state or local restrictions or prohibitions are adopted in our areas of operations, such as in the Wattenberg field, our customers, including Anadarko, may incur significant compliance costs or may experience delays or curtailment in the pursuit of their exploration, development, or production activities, and possibly be limited or precluded in the drilling of certain wells altogether. Any adverse impact on our customers' activities would have a corresponding negative impact on our throughput volumes. Accordingly, such restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, cash flows, and ability to make distributions to our unitholders. Increased regulation of the hydraulic fracturing process could also lead to greater opposition to, and litigation over, oil and gas production activities using hydraulic fracturing techniques.
For example, in exchange for the withdrawal of several initiatives relating to hydraulic fracturing and other oil and gas operations proposed for inclusion on the Colorado state ballot in November 2014, the governor of Colorado created the Task Force on State and Local Regulation of Oil and Gas Operations in September 2014 to make recommendations to the state legislature regarding the responsible development of Colorado's oil and gas resources. Although it is early in the process, it is possible that, as a result of the task force's recommendations, Colorado could adopt new policies or legislation relating to oil and natural-gas operations, including measures that would give local governments in Colorado greater authority to limit hydraulic fracturing and other oil and natural-gas operations or require greater distances between well sites and occupied structures. Moreover, states could elect to prohibit hydraulic fracturing altogether, as the state of New York did in December 2014.
In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general and/or hydraulic fracturing in particular. Further, several federal governmental agencies are conducting reviews and studies on the environmental aspects of hydraulic fracturing activities, including the White House Council on Environmental Quality and the EPA, with the EPA planning to issue a draft of its final report on hydraulic fracturing in the first half of 2015. The results of these existing or any future reviews and studies could spur initiatives to further regulate hydraulic fracturing.

Adverse developments in our geographic areas of operation could disproportionately impact our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Our business and operations are concentrated in a limited number of producing areas. Due to our limited geographic diversification, adverse operational developments, regulatory or legislative changes, or other events in an area in which we have significant operations could have a greater impact on our business, results of operations, financial condition and ability to make cash distributions to our unitholders than they would if our operations were more diversified.

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We may not be able to obtain funding on acceptable terms or at all. 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, especially for companies involved in oil and natural gas exploration and production. 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 RCF 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, cash flows and ability to make cash distributions to our unitholders.

Restrictions in the indentures governing our 5.375% Senior Notes due 2021 (the "2021 Notes"), 4.000% Senior Notes due 2022 (the "2022 Notes"), 2.600% Senior Notes due 2018 (the "2018 Notes"), 5.450% Senior Notes due 2044 (the "2044 Notes" and together with the 2021 Notes, the 2022 Notes, and the 2018 Notes "the Notes") or the RCF may limit our ability to capitalize on acquisitions and other business opportunities.

The operating and financial restrictions and covenants in the indentures governing the Notes and in the RCF 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. The RCF contains, and with respect to the second, fourth and fifth bullets below, the indentures governing the Notes contain, covenants that restrict or limit our ability to do the following:

- incur additional indebtedness or guarantee other indebtedness;
- grant liens to secure obligations other than our obligations under the Notes or RCF or agree to restrictions on our ability to grant additional liens to secure our obligations under the Notes or RCF;
- engage in transactions with affiliates;
- make any material change to the nature of our business from the midstream energy business; or
- enter into a merger, consolidate, liquidate, wind up or dissolve.

The RCF also contains various customary covenants, customary events of default and a maximum consolidated leverage ratio as of the end of each quarter (which is defined as the ratio of consolidated indebtedness as of the last day of a fiscal quarter to Consolidated Earnings Before Interest, Taxes, Depreciation and Amortization for the most recent four consecutive fiscal quarters ending on such day) of 5.0 to 1.0, or a consolidated leverage ratio of 5.5 to 1.0 with respect to quarters ending in the 270-day period immediately following certain acquisitions. See Item 7 of this Form 10-K for a further discussion of the terms of our RCF and Notes.

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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.

Our 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 effect 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 RCF, 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.

A downgrade or other negative credit-rating action with respect to our or Anadarko’s credit rating could negatively impact our cost of, and ability to access, capital.

We cannot provide assurance that our credit ratings or those of Anadarko will not be downgraded, or that other adverse credit-rating events will not occur. A downgrade or notice of potential downgrade of either our or Anadarko’s credit ratings could negatively impact our ability to access the capital markets, increase our borrowing costs, or limit our ability to effectively execute aspects of our strategy.

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If Anadarko were to limit transfers 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 or the timing of those volumes, revenues or costs, including synergies;
- an inability to successfully integrate the acquired assets or businesses;
- 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.

The amount of cash we have available for distribution to holders of our common units depends primarily on our cash flows rather than on our profitability. As a result, 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 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 required to pay the distribution announced for the quarter ended December 31, 2014, on all of our common units, general partner units and IDRs was \$126.0 million, or \$504.2 million per year. The Class C unit distribution, if paid in cash, would have been \$3.1 million for the quarter ended December 31, 2014.

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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, or the timeline for the development of reserves is greater than we anticipate, and we are unable to secure additional sources of natural gas, there could be a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

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

We compete with similar enterprises in our areas of operation. Our competitors may expand or construct 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 Anadarko 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, 2014, we had $384.4 million of goodwill on our balance sheet. Goodwill is recorded when the purchase price of a business acquired exceeds the fair market value of the tangible and separately measurable intangible net assets. In addition, similar to the carrying value of the assets we acquired from Anadarko, part of 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 sustained lower oil and natural gas prices, reduce the fair value of the associated reporting unit. Future non-cash asset impairments could negatively affect our results of operations.

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If third-party pipelines or other facilities interconnected to our gathering, transportation, treating or processing 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, transportation, treating and processing 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, treat or process 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.

Our interstate natural gas and liquids transportation assets and operations are subject to regulation by FERC, which could have an adverse effect on our revenues and our ability to make distributions.

Our interstate natural gas pipelines are subject to regulation by FERC under the NGA and the EPAct 2005. If 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 to impose penalties for current violations of the NGA or NGPA 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.
Our interstate liquids pipelines are common carriers and are subject to regulation by FERC under the Interstate Commerce Act, the Energy Policy Act of 1992, and related rules and orders.
FERC regulation requires that common carrier liquid pipeline rates and interstate natural gas pipeline rates be filed with FERC and that these rates be “just and reasonable” and not unduly discriminatory. Interested persons may challenge proposed new or changed rates, and FERC is authorized to suspend the effectiveness of such rates pending an investigation or hearing. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Accordingly, action by FERC could adversely affect our ability to establish reasonable rates that cover operating costs and allow for a reasonable return. An adverse determination in any future rate proceeding brought by or against us could have a material adverse effect on our business, financial condition, results of operations, and cash available for distribution. For example, one such matter relates to FERC’s policy regarding allowances for income taxes in determining a regulated entity’s cost of service. FERC allows regulated companies to recover an allowance for income taxes in rates only to the extent the company or its owners, such as our unitholders, are subject to U.S. income tax. This policy affects whom we allow to own our units, and if we are not successful in limiting ownership of our units to persons or entities subject to U.S. income tax, our FERC-regulated rates and revenues for our FERC-regulated gas and liquids pipelines could be adversely affected.

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.

We believe that our gathering systems meet the traditional tests FERC has used to determine if a pipeline is a gathering pipeline and is, therefore, not subject to FERC jurisdiction. FERC, however, has not made any determinations with respect to the jurisdictional status of any of these gathering systems. The distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of ongoing litigation and, over time, FERC policy concerning which activities it regulates and which activities are excluded from its regulation has changed. 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 regulated the gathering activities of interstate pipeline transmission companies more lightly, which has resulted in a number of such companies transferring gathering facilities to unregulated affiliates. As a result of these activities, natural gas gathering may begin to receive greater regulatory scrutiny at both the state and federal levels.

FERC makes jurisdictional determinations for both natural gas gathering and liquids lines on a case-by-case basis. The classification and regulation of our pipelines are subject to change based on future determinations by FERC, the courts or Congress. 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.

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Climate change legislation or regulatory initiatives could increase our operating and capital costs and could decrease demand for our midstream services.

The EPA has adopted regulations under the Clean Air Act that establish construction and operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions. Facilities subject to these permitting requirements for their GHG emissions also will be required to meet BACT standards that typically are established by the states. Compliance with these permitting programs could restrict or delay our ability to obtain air permits for new or modified sources. The EPA has also adopted rules establishing a reporting program requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States including, among others, onshore processing, transmission, storage and distribution facilities. In January 2015, the Obama Administration announced plans to reduce GHGs by regulating methane emissions from the oil and natural gas sector. The Obama Administration stated that they will seek to reduce methane emissions in the oil and natural gas sector by 40 to 45 percent from 2012 levels by 2025. There are a number of elements involved in the plan, including efforts by the EPA, DOT and Department of the Interior. As to the EPA, the Obama Administration announced that the EPA will propose new source rules for methane this summer and seek to finalize them in 2016.

Congress has from time to time considered legislation to reduce emissions of GHGs, and a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emissions allowances in return for emitting those GHGs. 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 GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs 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 financial position, results of operations and cash available for distribution to our unitholders.

Derivatives legislation 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 Dodd-Frank Act, among other things, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us and Anadarko, that participate in that market. The Dodd-Frank Act requires the Commodity Futures Trading Commission (the “CFTC”), the SEC and other federal regulators to promulgate rules and regulations implementing the Dodd-Frank Act. The CFTC has finalized the majority of its regulations, but others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished or what the terms of the final rules will be.

In its rulemaking under the Dodd-Frank Act, the CFTC has proposed regulations to set position limits for certain futures contracts in designated physical commodities including, among others, oil and natural gas, and for options and swaps that are their economic equivalent. Certain bona fide hedging positions would be exempt from these position limits under the regulations as currently proposed. It is not possible at this time to predict when the CFTC will finalize these regulations or whether the proposed rules will be modified prior to becoming effective, so the impact of those provisions on us is uncertain at this time.

As part of the Dodd-Frank reforms, the CFTC has designated certain types of swaps (thus far, interest rate swaps and credit default swaps) for mandatory clearing and exchange trading, and may designate other types of swaps for mandatory clearing and exchange trading in the future. To the extent we engage in such transactions or transactions that become subject to such rules in the future, we will be required to comply or to take steps to qualify for an exemption to such requirements. Although we are availing ourselves of the end-user exception to the mandatory clearing and exchange trading requirements for swaps designed to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we and Anadarko use for hedging.

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The Dodd-Frank Act requires that regulators establish margin rules applicable to uncleared swaps. However, a recent amendment to the act and the CFTC's proposed margin rule exempt from the margin requirements certain uncleared swaps with end users. It is not possible at this time to predict whether the proposed rule will be modified to impose any limitations on the exemption. To the extent that any final margin rules limit the exemption with respect to our swaps activity, we could be required to post initial or variation margin, which would impact liquidity and reduce our cash. This would in turn reduce our ability to execute hedges to reduce risk and protect cash flows.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter and reduce our ability to monetize or restructure our existing commodity price contracts. The financial reform legislation may also require some counterparties to spin off some of their derivative activities to separate entities that may not be as creditworthy, thereby increasing the credit risk associated with our hedging activities. 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. Further, to the extent our revenues are unhedged, they could be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations. At this time, the impact of such regulations is not clear.

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

Pursuant to authority under the NGPSA and the HLPSA, as amended by the PSI Act, the PIPES Act and the 2011 Pipeline Safety Act, PHMSA has promulgated regulations requiring pipeline operators to develop and implement integrity management programs for certain gas and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect "high consequence areas," which are areas where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources and unusually sensitive ecological areas. These regulations require the operators of covered pipelines to: (i) perform ongoing assessments of pipeline integrity; (ii) identify and characterize applicable threats to pipeline segments that could impact a high consequence area; (iii) improve data collection, integration and analysis; (iv) repair and remediate the pipeline as necessary; and (v) implement preventive and mitigating actions. In addition, states have adopted regulations similar to existing PHMSA regulations for certain intrastate gas and hazardous liquid pipelines. At this time, we cannot predict the ultimate cost of compliance with these regulations, 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 for repairs or upgrades deemed necessary to ensure the safe and reliable operation of our pipelines.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.

The 2011 Pipeline Safety Act is the most recent federal legislation to amend the NGPSA and HLPSA pipeline safety laws, requiring increased safety measures for gas and hazardous liquids pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, material strength testing, and verification of the maximum allowable pressure of certain pipelines. The 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day of violation and from $1.0 million to $2.0 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any implementation of PHMSA rules thereunder could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position.

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, tribal, state and local environmental laws and regulations governing the discharge of materials into the environment or otherwise relate to environmental protection. These environmental 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 liabilities 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.

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. These uncertainties could also affect downstream assets which we do not own or control, but which are critical to certain of our growth projects. Delays in the completion of new downstream assets, or the unavailability of existing downstream assets, due to environmental, regulatory or political considerations, could have an adverse impact on the completion or utilization of our growth projects. In addition, construction activities could be subject to state, county and local ordinances that restrict the time, place or manner in which those activities may be conducted. Construction 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.

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We have partial ownership interests in several joint venture legal entities which we do not operate or control. As a result, among other things, 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, White Cliffs, Rendezvous and Mont Belvieu JV entities in which we have a minority ownership interest, we are 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, White Cliffs, Rendezvous or the Mont Belvieu JV 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 membership interest in Chipeta, we became party to Chipeta's limited liability company agreement, as amended and restated (the "Chipeta LLC agreement"). 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 are 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 position 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, natural resource damages and/or suspension of operations.

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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 or natural resource 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 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, 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 depends, in part, on our ability to attract and retain experienced engineering, operating, commercial and other professionals. Competition for such professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be adversely impacted.

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

Our partnership agreement requires us to deduct estimated, rather than actual, maintenance capital expenditures from operating surplus. The amount of estimated maintenance capital expenditures deducted from operating surplus will be subject to review and change by the Special Committee of our general partner’s Board of Directors 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 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 to make the expenditures required 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, through its control of WGP, controls our general partner, which has sole responsibility for conducting our business and managing our operations. Anadarko, WGP and our general partner have conflicts of interest with, and may favor Anadarko's interests to the detriment of, our unitholders.

Anadarko, through its control of WGP, controls our general partner and indirectly has the power to appoint all of the officers and directors of our general partner. Although our general partner has a 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, WGP, in which Anadarko holds a controlling general partner interest and an 88.3% limited partner interest. Conflicts of interest may arise between Anadarko, WGP 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 and WGP 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 default state law 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 under state law.
- 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.
- 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 IDR payments.
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Our partnership agreement permits us to classify up to $31.8 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions to our general partner in respect of the general partner interest or the IDRs.

- 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.

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- Our general partner intends to limit its liability regarding our contractual and other obligations.
- Our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units.
- Our general partner controls the enforcement of the obligations that it and its affiliates owe to us.
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.
- Our general partner may elect to cause us to issue Class B units to it in connection with a resetting of the target distribution levels related to the IDRs 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 Form 10-K.

The duties of our general partner's officers and directors may conflict with their duties as officers and directors of WGP's general partner.

Our general partner's officers and directors have duties to manage our business in a manner that is beneficial to us, our unitholders and the owner of our general partner, WGP, which is in turn controlled by Anadarko. However, a majority of our general partner's directors and all of its officers are also officers and/or directors of WGP's general partner, which has duties to manage the business of WGP in a manner beneficial to WGP and WGP's unitholders, including Anadarko. Consequently, these directors and officers may encounter situations in which their obligations to us on the one hand, and WGP and/or Anadarko, on the other hand, are in conflict. The resolution of these conflicts may not always be in our best interest or that of our unitholders.
In addition, our general partner's officers, who are also the officers of WGP's general partner and certain of whom are officers of Anadarko, will have responsibility for overseeing the allocation of their own time and time spent by administrative personnel on our behalf and on behalf of WGP and/or Anadarko. These officers may face conflicts regarding these time allocations.

Neither Anadarko nor WGP is limited in its ability to compete with us or is 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.

Neither Anadarko nor WGP is prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, in the future, Anadarko or WGP 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 participate in such transactions. 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 are substantial and reduce our cash available for distribution to our unitholders. The amount and timing of such reimbursements are determined by our general partner.

Prior to making distributions on our common units, we reimburse Anadarko, which controls our general partner, and its affiliates for 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 reduce the amount of cash otherwise available for distribution to our unitholders.

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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 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 has included provisions in its and our contractual arrangements that limit its liability 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 duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

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

We expect that we will continue to distribute all of our available cash to our unitholders and will continue to 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.
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, the indenture governing the Notes or in our RCF 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 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;

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- whether to exercise its registration rights;
- whether to elect to reset target distribution levels; and
- whether to consent to any merger or consolidation of the Partnership or amendment to the partnership agreement.

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

Our partnership agreement restricts the remedies available to holders of our common 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 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 IDRs, 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 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 IDRs 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 IDRs 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 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 is chosen by Anadarko (through its control of WGP). Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

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

Unitholders are currently unable to remove our general partner without its consent because our general partner and its affiliates currently own a sufficient percentage of the outstanding units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding units (including general partner units, common units and Class C units) voting together as a single class is required to remove our general partner. As of February 23, 2015, WGP owned a 34.9% limited partner interest in us. Other subsidiaries of Anadarko separately owned an aggregate 8.3% limited partner interest in us, consisting of common and Class C units. As such, Anadarko has the ability to prevent the removal of our general partner.

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

Unitholders’ voting rights are restricted by a provision of our partnership agreement providing that any person or group 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 our unitholders. Furthermore, our partnership agreement does not restrict the ability of (i) WGP to transfer all or a portion of its ownership interest in our general partner to a third party, or (ii) Anadarko to transfer all or a portion of its ownership interest in WGP and/or WGP’s general partner to a third party. The new owner of our general partner or WGP’s general partner, as the case may be, 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;
- 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.

WGP or affiliates 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 23, 2015, WGP held 49,296,205 common units and other subsidiaries of Anadarko held 757,619 common units and 10,959,564 Class C units. Additionally, the Class C units are entitled to receive distributions in the form of additional Class C units, which will increase the number of our common and Class C units owned by affiliates over time. 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 23, 2015, WGP owned a 34.9% limited partner interest in us, and other subsidiaries of Anadarko held an aggregate 8.3% limited partner interest in us, consisting of common and Class C units.

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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

- such 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.

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 (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.

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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 investor or analyst estimates of Anadarko’s and our financial performance or our future distribution growth;
- the public’s reaction to Anadarko’s or our press releases, announcements and filings with the SEC;
- legislative or regulatory changes affecting our status as a partnership for federal income tax purposes;
- 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.

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TAX RISKS TO COMMON UNITHOLDERS

Our taxation as a flow-through entity depends on our status as a partnership for U.S. 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 ("IRS") were to treat us as a corporation for federal income tax purposes or if we were to become subject to material 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 U.S. federal income tax purposes. Despite the fact that we are organized as a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as us to be treated as a corporation for federal income tax purposes unless it satisfies a "qualifying income" requirement and is not treated as an investment company. Based on our current operations, we believe that we satisfy the qualifying income requirement, and we are not treated as an investment company. Failing to meet the qualifying income requirement, being treated as an investment company, a change in our business activities, 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. We have not requested, and do not plan to request, a ruling from the IRS on these or any other tax matters affecting our partnership tax treatment.

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 our unitholders, likely causing a substantial reduction in the value of our common units.

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 taxes, franchise taxes and other forms of taxation. For example, we are required to pay Texas margin tax on our gross income apportioned to Texas. Imposition of any additional such taxes on us or an increase in the existing tax rates would reduce the cash available for distribution to our unitholders.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, the Obama administration's budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. From time to time, members of Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. If successful, the Obama administration's proposal, or other similar proposals, could eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations, upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

Any modifications to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S.

federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

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If the IRS contests the federal income tax positions we take, 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 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. Such a reallocation may require us and our unitholders to file amended tax returns. Any contest by the IRS may materially and adversely impact the market for our common units and the price at which they trade. 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 are required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Our unitholders are required to pay federal income taxes and, in some cases, state and local income taxes, on their share of our taxable income, whether or not they receive cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax due with respect to that income.

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

If a unitholder sells 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 result in a decrease in 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 that unitholder, if that unitholder sells such units at a price greater than that unitholder's 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 of depreciation deductions and certain other items. In addition, because the amount realized includes a unitholder's share of our non-recourse liabilities, if a unitholder sells units, that unitholder 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.

Investments in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (or "IRAs"), and non-U.S. persons raise 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 are subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. persons, and each non-U.S. person will be required to file U.S. federal tax returns and pay tax on its share of our taxable income. Any tax-exempt entity or a non-U.S. person should consult its tax advisor before investing in our common units.

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We treat each purchaser of our common units as having the same tax benefits without regard to the common units actually 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 have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. 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 prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common 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 generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. Nonetheless, we allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service. The use of this proration method may not be permitted under existing Treasury Regulations, and although the U.S. Treasury Department issued proposed Treasury Regulations allowing a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method we have adopted. If the IRS were to successfully challenge our proration method or new Treasury Regulations were to be issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of common units) may be considered to have 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 there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, 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 and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, 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 of their common units should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, which could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our assets. Although we may, from time to time, consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the timing or 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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The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the constructive termination of our partnership for federal income tax purposes.

We will be considered to have terminated as a 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. WGP directly and indirectly owns a significant portion of the total interest in our capital and profits. Therefore, a transfer by WGP of all or a portion of its interest in us (or a constructive termination of WGP) could, in conjunction with the trading of common units held by the public or other subsidiaries of Anadarko, result in a termination of our partnership for federal income tax purposes. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could cause a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than the calendar year, 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. A constructive termination would not affect our classification as a partnership for federal income tax purposes, but instead, after our termination we would be treated as a new partnership for federal income 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 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 U.S. 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 now or in the future, 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. As we make acquisitions or expand our business, we may own assets or conduct business in additional states or foreign jurisdictions that impose a personal income tax. It is the responsibility of each unitholder to file all U.S. federal, foreign, state and local tax returns.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

WGR Operating, LP, one of our subsidiaries, is currently in negotiations with the U.S. Environmental Protection Agency with respect to alleged non-compliance with the leak detection and repair requirements of the federal Clean Air Act at its Granger, Wyoming facility. Although management cannot predict the outcome of settlement discussions, management believes that it is reasonably likely a resolution of this matter will result in a fine or penalty in excess of $100,000.
Except as discussed above, 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 a 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 Form 10-K for more information.

Item 4. Mine Safety Disclosures

Not applicable.

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PART II

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

MARKET INFORMATION

Our common units are listed on the New York Stock Exchange under the symbol "WES." The following table sets forth the high and low sales prices of the common units and the cash distribution per unit declared for the periods presented.

	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
2014				
High Price	$75.29	$79.81	$76.57	$66.50
Low Price	60.09	71.15	65.51	58.50
Distribution per common unit	0.700	0.675	0.650	0.625
2013				
High Price	$64.07	$65.16	$65.11	$59.81
Low Price	57.54	54.58	55.57	46.82
Distribution per common unit	0.600	0.580	0.560	0.540

As of February 23, 2015, there were 26 unitholders of record of our 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 2,583,068 general partner units and 10,959,564 Class C units for which there is no established public trading market. All general partner units are held by our general partner and all Class C units are held by a subsidiary of Anadarko.

OTHER SECURITIES MATTERS

Unregistered sales of equity securities and use of proceeds. In connection with our November 2014 equity offering, our general partner purchased 153,061 general partner units for $10.8 million in cash. Proceeds from the November 2014 equity offering, including from the sale of the general partner units, were primarily used to fund the acquisition of DBM. The general partner units were issued in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended.

Securities authorized for issuance under equity compensation plans. In connection with the closing of our IPO, our general partner adopted the Western Gas Partners, LP 2008 Long-Term Incentive Plan (the "WES LTIP"), which permits the issuance of up to 2,250,000 units, of which 2,133,227 units remained available for future issuance as of December 31, 2014. Phantom unit grants under the WES LTIP have been made to each of the independent directors of our general partner and certain employees. Please read the information under Item 12 of this Form 10-K, which is incorporated by reference into this Item 5.

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Class C Unit Issuance. In connection with the closing of the DBM acquisition in November 2014, we issued 10,913,853 Class C units to APC Midstream Holdings, LLC ("AMH"), a subsidiary of Anadarko, at a price of $68.72 per unit, pursuant to the Unit Purchase Agreement ("UPA") with Anadarko and AMH. All outstanding Class C units will convert into common units on a one-for-one basis on December 31, 2017, unless we elect to convert such units earlier or Anadarko extends the conversion date. The distributions that Class C units receive are paid in the form of additional Class C units ("PIK C units") until the end of 2017 (unless earlier converted), and the Class C units are disregarded with respect to distributions of available cash until they are converted to common units. The terms of the Class C unit issuance were unanimously approved by the Board of Directors of our general partner and by the Board's Special Committee. On February 12, 2015, the Partnership's general partner distributed 45,711 PIK C units to the Class C unitholder. The Class C units were issued in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended.

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 and the IDRs.

Available cash. The partnership agreement requires us to distribute all of our available cash (as defined in our partnership agreement) to unitholders of record on the applicable record date within 45 days of the end of each quarter. The amount of available cash generally is all cash on hand at the end of the quarter, plus, at the discretion of our 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, debt instruments or other agreements; or to provide funds for distributions to our unitholders, and to our general partner for any one or more of the next four quarters. Working capital borrowings generally include borrowings made under a credit facility or similar financing arrangement. It is intended that working capital borrowings be repaid within 12 months. In all cases, working capital borrowings are used solely for working capital purposes or to fund distributions to partners. Class C units are disregarded with respect to distributions of available cash until they are converted to common units.

General partner interest and incentive distribution rights. As of December 31, 2014, our general partner was entitled to 1.9% of all quarterly distributions that we make prior to our liquidation (see Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K). Our general partner, as the holder of the IDRs, was entitled to incentive distributions at the maximum distribution sharing percentage of 48.0% for all periods presented.

	Total Quarterly Distribution Target Amount	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum quarterly distribution	$0.300	98.1%	1.9%
First target distribution	up to $0.345	98.1%	1.9%
Second target distribution	above $0.345 up to $0.375	85.1%	14.9%
Third target distribution	above $0.375 up to $0.450	75.1%	24.9%
Thereafter	above $0.450	50.1%	49.9%

The maximum distribution sharing percentage of 49.9% includes distributions paid to our general partner on its 1.9% general partner interest and the 48.0% IDR maximum distribution sharing percentage, and does not include any distributions that our general partner may receive on common units that it may acquire.

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Item 6. Selected Financial and Operating Data

Unless the context otherwise requires, references to “we,” “us,” “our,” the “Partnership” or “Western Gas Partners” refer to Western Gas Partners, LP and its subsidiaries. Our general partner, Western Gas Holdings, LLC (the “general partner” or “GP”), is owned by Western Gas Equity Partners, LP (“WGP”), a Delaware master limited partnership formed by Anadarko Petroleum Corporation. Western Gas Equity Holdings, LLC is WGP’s general partner and is a wholly owned subsidiary of Anadarko Petroleum Corporation. “Anadarko” refers to Anadarko Petroleum Corporation and its subsidiaries, excluding us and our general partner, and “affiliates” refers to subsidiaries of Anadarko, excluding us, and includes equity interests in Fort Union Gas Gathering, LLC (“Fort Union”), White Cliffs Pipeline, LLC (“White Cliffs”), Rendezvous Gas Services, LLC (“Rendezvous”), Enterprise EF78 LLC (the “Mont Belvieu JV”), Texas Express Pipeline LLC (“TEP”), Texas Express Gathering LLC (“TEG”) and Front Range Pipeline LLC (“FRP”). The interests in TEP, TEG and FRP are referred to collectively as the “TEFR Interests.” All income earned on, distributions from and contributions to, our equity investments are considered to be affiliate transactions. “Equity investment throughput” refers to our 14.81% share of average Fort Union throughput and our 22% share of average Rendezvous throughput, but excludes throughput measured in barrels, consisting of our 10% share of average White Cliffs throughput, our 25% share of average Mont Belvieu JV throughput, our 20% share of average TEP and TEG throughput and our 33.33% share of average FRP throughput. The “DJ Basin complex” refers to the Platte Valley system, Wattenberg system and Lancaster plant, all of which were combined into a single complex in the first quarter 2014.
The term “Partnership assets” refers to the assets owned and interests accounted for under the equity method by us as of December 31, 2014 (see Note 9—Equity Investments in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K). Because Anadarko controls us through its ownership and control of WGP, which owns the entire interest in our general partner, each of our acquisitions of Partnership assets from Anadarko has been considered a transfer of net assets between entities under common control. As such, the Partnership assets we acquired from Anadarko were initially recorded at Anadarko’s historic carrying value, which did not correlate to the total acquisition price paid by us (see Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K). Further, after an acquisition of Partnership assets from Anadarko, we may be required to recast our financial statements to include the activities of such Partnership assets from the date of common control. For those periods requiring recast, the consolidated financial statements for periods prior to our acquisition of Partnership assets from Anadarko, 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 we had owned the Partnership assets during the periods reported. For ease of reference, we refer to the historical financial results of the Partnership assets prior to our acquisitions from Anadarko as being “our” historical financial results.

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Acquisitions

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, concurrently with the closing of our initial public offering ("IPO"), Anadarko contributed to us the assets and liabilities of Anadarko Gathering Company LLC ("AGC"), Pinnacle Gas Treating LLC ("PGT") and MIGC LLC ("MIGC"), which we refer to as our "initial assets." In December 2008, we completed the acquisition of the Powder River assets from Anadarko, which included (i) the Hilight system, (ii) a 50% interest in the Newcastle system and (iii) a 14.81% membership interest in Fort Union. In July 2009, we closed on the acquisition of a 51% membership interest in Chipeta Processing LLC ("Chipeta") from Anadarko. We closed the acquisitions of Anadarko's Granger and Wattenberg assets in January 2010 and August 2010, respectively. In September 2010, we acquired a 10% interest in White Cliffs, which consisted of a 9.6% third-party interest, and a 0.4% interest from Anadarko. In February 2011, we acquired the Platte Valley gathering system and processing plant from a third party, and in July 2011, we acquired the Bison gas treating facility from Anadarko. In January 2012, we acquired Mountain Gas Resources, LLC ("MGR") from Anadarko, which acquisition included the Patrick Draw processing plant, the Red Desert processing plant, gathering lines, and related facilities (collectively, the "Red Desert complex"), and the 22% interest in Rendezvous, which are collectively referred to as the "MGR assets." In August 2012, we acquired Anadarko's then-remaining 24% membership interest in Chipeta (the "additional Chipeta interest"), receiving distributions related to the additional interest effective July 1, 2012. In March 2013, we completed the acquisition of a 33.75% interest (the "Non-Operated Marcellus Interest") in both the Liberty and Rome gas gathering systems from a wholly owned subsidiary of Anadarko, Anadarko Marcellus Midstream, L.L.C. Also in March 2013, we completed the acquisition of a 33.75% interest (the "Anadarko-Operated Marcellus Interest") in the Larry's Creek, Seely and Warrensville gas gathering systems from a third party. In June 2013, we acquired a 25% interest in the Mont Belvieu JV from a third party, and in September 2013, we acquired Overland Trail Transmission, LLC, ("OTTCO") from a third party. In March 2014, we acquired the TEFR Interests from Anadarko. In November 2014, we acquired Nuevo Midstream, LLC ("Nuevo") from a third party. Following the acquisition, we changed the name of Nuevo to Delaware Basin Midstream, LLC ("DBM").

Dates of common control

In connection with its August 23, 2006, acquisition of Western Gas Resources, Inc., Anadarko acquired MIGC, the Powder River assets, the Granger assets and the MGR assets. Anadarko acquired the Wattenberg assets and a 75% interest in Chipeta in connection with its August 10, 2006, acquisition of Kerr-McGee Corporation. Anadarko made its initial investment in White Cliffs on January 29, 2007.

Our consolidated financial statements include (i) the combined financial results and operations of AGC and PGT for all periods presented, (ii) the consolidated financial results and operations of Western Gas Partners, LP and its subsidiaries combined with the financial results and operations of MIGC, the Powder River assets, the Granger assets, the MGR assets, the Chipeta assets, the Wattenberg assets, the 0.4% interest in White Cliffs, and the Non-Operated Marcellus Interest, for all periods presented, (iii) the financial results and operations of the Bison assets from 2009 (when Anadarko began construction of such assets, which were subsequently placed in service in June 2010), and (iv) the financial results and operations of the TEFR Interests from 2011 when Anadarko made its initial investment in the respective businesses. Effective August 1, 2012, noncontrolling interests exclude the financial results and operations of the additional Chipeta interest.

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The information in the following table should be read together with the information in the captions How We Evaluate Our Operations, Items Affecting the Comparability of Our Financial Results, Results of Operations, and Key Performance Metrics under Item 7 of this Form 10-K:

thousands except per-unit data, throughput, Adjusted gross margin per Mcf and Adjusted gross margin per Bbl	Summary Financial Information				
	2014	2013	2012	2011	2010
Statement of Income Data (for the year ended):					
Total revenues	$1,273,763	$1,029,763	$894,476	$858,144	$655,646
Operating income	451,587	320,858	194,825	245,294	177,539
Net income	390,558	285,443	149,267	206,861	156,933
Net income attributable to noncontrolling interests	14,025	10,816	14,890	14,103	11,005
Net income attributable to Western Gas Partners, LP	376,533	274,627	134,377	192,758	145,928
General partner interest in net income (loss) (1)	120,980	69,633	28,089	8,599	3,067
Limited partners' interest in net income (1)	256,509	200,866	78,897	131,560	111,064
Net income per common unit (basic) (1)	2.13	1.83	0.84	1.64	1.66
Net income per common unit (diluted) (1)	2.12	1.83	0.84	1.64	1.66
Net income per subordinated unit (basic and diluted) (1)	—	—	—	1.28	1.61
Distributions per unit	2.650	2.280	1.960	1.655	1.440
Balance Sheet Data (at period end):					
Total assets	$6,751,631	$4,617,808	$3,863,558	$2,997,689	$2,345,255
Total long-term liabilities	2,537,194	1,535,312	1,284,176	860,092	649,414
Total equity and partners' capital	4,011,866	2,892,036	2,394,076	2,010,279	1,613,311
Cash Flow Data (for the year ended):					
Net cash flows provided by (used in):					
Operating activities	$534,807	$448,201	$338,047	$312,838	$252,898
Investing activities	(2,621,559)	(1,652,995)	(1,357,537)	(485,832)	(921,398)
Financing activities	2,053,078	885,541	1,212,912	372,479	625,590
Capital expenditures	(672,821)	(645,854)	(638,121)	(149,717)	(173,891)
Throughput (MMcf/d except throughput measured in barrels):					
Total throughput for natural gas assets	3,658	3,368	3,023	2,715	2,224
Throughput attributable to noncontrolling interests for natural gas assets	165	168	228	242	197
Total throughput attributable to Western Gas Partners, LP for natural gas assets (2)	3,493	3,200	2,795	2,473	2,027
Throughput (MBbls/d) for crude/NGL assets (3)	116	40	31	28	17
Key Performance Metrics (for the year ended):					
Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets (4)	$822,932	$654,924	$544,853	$516,038	$398,676
Adjusted gross margin for crude/NGL assets (5)	73,714	15,274	13,221	9,497	3,503
Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets (6)	0.65	0.56	0.53	0.57	0.54
Adjusted gross margin per Bbl for crude/NGL assets (7)	1.75	1.05	1.17	0.94	0.57
Adjusted EBITDA attributable to Western Gas Partners, LP (8)	645,969	457,773	377,929	361,653	264,694

Distributable cash flow [8]	531,136	380,529	309,945	319,294	237,372

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(1) Net income earned on and subsequent to the date of our acquisitions of Partnership assets is allocated to the general partner and the limited partners, including any subordinated and Class C unitholders, in accordance with their respective weighted-average ownership percentages, and when applicable, giving effect to incentive distributions allocable to the general partner. Prior to our acquisition of the Partnership assets, all income is attributed to Anadarko. All subordinated units were converted into common units on August 15, 2011, on a one-for-one basis. For purposes of calculating net income per common and subordinated unit, the conversion of the subordinated units is deemed to have occurred on July 1, 2011. See Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

(2) Includes affiliate, third-party and equity investment throughput, excluding the noncontrolling interest owners' proportionate share of throughput.

(3) Represents total throughput measured in barrels consisting of throughput from our Chipeta NGL pipeline, our 10% share of average White Cliffs throughput, our 25% share of average Mont Belvieu JV throughput, our 20% share of average TEG and TEP throughput and our 33.33% share of average FRP throughput.

(4) Calculated as total revenues for natural gas assets less cost of product for natural gas assets plus distributions from our equity investments in Fort Union and Rendezvous, which are measured in Mcf, and excluding the noncontrolling interest owners' proportionate share of revenue and cost of product.

(5) Calculated as total revenues for crude/NGL assets less cost of product for crude/NGL assets plus distributions from our equity investments in White Cliffs, the Mont Belvieu JV, and the TEFR Interests, which are measured in barrels.

(6) Average for period. Calculated as Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets (as defined under the caption How We Evaluate Our Operations under Item 7 of this Form 10-K) divided by total throughput (MMcf/d) attributable to Western Gas Partners, LP for natural gas assets.

(7) Average for period. Calculated as Adjusted gross margin for crude/NGL assets (as defined under the caption How We Evaluate Our Operations under Item 7 of this Form 10-K), divided by total throughput (MBbls/d) for crude/NGL assets.

(8) Adjusted EBITDA attributable to Western Gas Partners, LP ("Adjusted EBITDA") and Distributable cash flow are not defined in the generally accepted accounting principles in the United States ("GAAP"). For definitions 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 Form 10-K.

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

Western Gas Partners, LP is a growth-oriented master limited partnership ("MLP") formed by Anadarko Petroleum Corporation in 2007. For purposes of this report, "we," "us," "our," the "Partnership" or "Western Gas Partners" refer to Western Gas Partners, LP and its subsidiaries. Our general partner, Western Gas Holdings, LLC (the "general partner" or "GP"), is owned by Western Gas Equity Partners, LP ("WGP"), a Delaware MLP formed by Anadarko Petroleum Corporation. Western Gas Equity Holdings, LLC is WGP's general partner and is a wholly owned subsidiary of Anadarko Petroleum Corporation. "Anadarko" refers to Anadarko Petroleum Corporation and its subsidiaries, excluding us and our general partner, and "affiliates" refers to subsidiaries of Anadarko, excluding us, and includes equity interests in Fort Union Gas Gathering, LLC ("Fort Union"), White Cliffs Pipeline, LLC ("White Cliffs"), Rendezvous Gas Services, LLC ("Rendezvous"), Enterprise EF78 LLC (the "Mont Belvieu JV"), Texas Express Pipeline LLC ("TEP"), Texas Express Gathering LLC ("TEG") and Front Range Pipeline LLC ("FRP"). The interests in TEP, TEG and FRP are referred to collectively as the "TEFR Interests." All income earned on, distributions from and contributions to, our equity investments are considered to be affiliate transactions. "Equity investment throughput" refers to our 14.81% share of average Fort Union throughput and our 22% share of average Rendezvous throughput, but excludes throughput measured in barrels, consisting of our 10% share of average White Cliffs throughput, our 25% share of average Mont Belvieu JV throughput, our 20% share of average TEP and TEG throughput and our 33.33% share of average FRP throughput. The "DJ Basin complex" refers to the Platte Valley system, Wattenberg system, and Lancaster plant, all of which were combined into a single complex in the first quarter of 2014. In November 2014, we completed the acquisition of Nuevo Midstream, LLC ("Nuevo") from a third party. Following the acquisition, we changed the name of Nuevo to Delaware Basin Midstream, LLC ("DBM").

The term "Partnership assets" refers to the assets owned and interests accounted for under the equity method by us as of December 31, 2014 (see Note 9—Equity Investments in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K). Because Anadarko controls us through its ownership and control of WGP, which owns the entire interest in our general partner, each of our acquisitions of Partnership assets from Anadarko has been considered a transfer of net assets between entities under common control. As such, the Partnership assets we acquired from Anadarko were initially recorded at Anadarko's historic carrying value, which did not correlate to the total acquisition price paid by us (see Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K). Further, after an acquisition of Partnership assets from Anadarko, we may be required to recast our financial statements to include the activities of such Partnership assets from the date of common control. For those periods requiring recast, the consolidated financial statements for periods prior to our acquisition of the Partnership assets from Anadarko, 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 we had owned the Partnership assets during the periods reported. For ease of reference, we refer to the historical financial results of the Partnership assets prior to our acquisitions from Anadarko as being "our" historical financial results.

The following discussion analyzes our financial condition and results of operations and should be read in conjunction with the consolidated financial statements and notes to consolidated financial statements, which are included in Item 8 of this Form 10-K.

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EXECUTIVE SUMMARY

We are a growth-oriented Delaware MLP formed by Anadarko to own, operate, acquire and develop midstream energy assets. We currently own or have investments in assets located in the Rocky Mountains (Colorado, Utah and Wyoming), the Mid-Continent (Kansas and Oklahoma), North-central Pennsylvania and Texas, and are engaged in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, NGLs and crude oil for Anadarko, as well as for third-party producers and customers. As of December 31, 2014, our assets and investments accounted for under the equity method consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Natural gas gathering systems	14	1	5	2
Natural gas treating facilities	8	—	—	1
Natural gas processing facilities	13	3	—	2
NGL pipelines	3	—	—	3
Natural gas pipelines	4	—	—	—
Oil pipeline	1	—	—	1

Significant financial and operational highlights during the year ended December 31, 2014 included the following:

- We completed the acquisition of DBM from a third party. DBM's assets serve production from Reeves, Loving and Culberson Counties, Texas and Eddy and Lea Counties, New Mexico. See Acquisitions under Items 1 and 2 of this Form 10-K for additional information.

- We issued 10,913,853 Class C units to a subsidiary of Anadarko, at a price of $68.72 per unit, generating proceeds of $750.0 million, all of which was used to fund a portion of the acquisition of DBM.

- We issued 8,620,153 common units to the public, generating net proceeds of $603.0 million, including the general partner's proportionate capital contribution, part of which was used to fund a portion of the acquisition of DBM.

- We issued 1,133,384 common units to the public under our Continuous Offering Program (as defined and discussed in Registered Securities within this Item 7), generating net proceeds of $83.2 million, including the general partner's proportionate capital contribution. Net proceeds were used for general partnership purposes, including funding capital expenditures. See Equity Offerings under Items 1 and 2 of this Form 10-K for additional information.

- In April 2014, we completed construction and commenced operations of the 300 MMcf/d Train I at the Lancaster plant (located in the DJ Basin complex) in Northeast Colorado. We are currently constructing the 300 MMcf/d Train II at the same plant, with operations expected to commence in the second quarter of 2015.

- We issued $400.0 million aggregate principal amount of 5.450% Senior Notes due 2044 and an additional $100.0 million aggregate principal amount of 2.600% Senior Notes due 2018. Net proceeds were used to repay amounts then outstanding under our RCF. See Liquidity and Capital Resources within this Item 7 for additional information.

- We completed the acquisition of Anadarko's 20% interests in TEG and TEP, and its 33.33% interest in FRP. See Acquisitions under Items 1 and 2 of this Form 10-K for additional information.

- We entered into an amended and restated $1.2 billion (expandable to $1.5 billion) senior unsecured RCF replacing our $800.0 million credit facility. See Liquidity and Capital Resources within this Item 7 for additional information.

- We raised our distribution to $0.70 per unit for the fourth quarter of 2014, representing a 4% increase over the distribution for the third quarter of 2014 and a 17% increase over the distribution for the fourth quarter of 2013.

- Throughput attributable to Western Gas Partners, LP for natural gas assets totaled 3,493 MMcf/d for the year ended December 31, 2014, representing a 9% increase compared to the year ended December 31, 2013.

- Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets (as defined under the caption How We Evaluate Our Operations within this Item 7) averaged $0.65 per Mcf for the year ended December 31, 2014, representing a 16% increase compared to the year ended December 31, 2013.

- Adjusted gross margin for crude/NGL assets (as defined under the caption How We Evaluate Our Operations within this Item 7) averaged $1.75 per Bbl for the year ended December 31, 2014, representing a 67% increase compared to the year ended December 31, 2013.

OUR OPERATIONS

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, 2014, 76% of our total revenues and 53% of our throughput (excluding equity investment throughput and throughput measured in barrels) were attributable to transactions with Anadarko. We receive significant dedications from our largest customer, Anadarko. With respect to our Wattenberg, Dew, Pinnacle, Haley, Helper, Clawson and Hugoton gathering systems, Anadarko has made a dedication to us that will continue to expand as long as additional wells are connected to these gathering systems.

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.

For the year ended December 31, 2014, 80% of our gross margin was attributable to fee-based contracts, under which a fixed fee is received based on the volume or 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 (i) we retain and sell drip condensate that is recovered during the gathering of natural gas from the wellhead or (ii) actual recoveries differ from contractual recoveries under a limited number of processing agreements. Fee-based gross margin includes equity income from our interests in Fort Union, White Cliffs, Rendezvous, the Mont Belvieu JV and the TEFR Interests.

For the year ended December 31, 2014, 20% of our gross margin, including gross margin attributable to condensate sales, was attributable to percent-of-proceeds and keep-whole contracts, pursuant to which we have commodity price exposure. A substantial majority of the commodity price risk associated with our percent-of-proceeds and keep-whole contracts is hedged under commodity price swap agreements with Anadarko. For the year ended December 31, 2014, 99% of our gross margin was derived from either long-term, fee-based contracts or from percent-of-proceeds or keep-whole agreements that were hedged with commodity price swap agreements. On December 31, 2014, our commodity price swap agreements for the Hilight and Newcastle systems and the Granger complex expired without renewal. See Risk Factors under Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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 Form 10-K.

As a result of our initial public offering "IPO" and subsequent acquisitions from Anadarko and third parties, our results of operations, financial position and cash flows may vary significantly for 2014, 2013 and 2012 as compared to future periods. Please see the caption Items Affecting the Comparability of Our Financial Results, set forth below in this Item 7.

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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) operating and maintenance expenses, (3) general and administrative expenses, (4) Adjusted gross margin (as defined below), (5) Adjusted EBITDA (as defined below) and (6) Distributable cash flow (as defined below).

Throughput. Throughput is an essential operating variable we use 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 the 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, 2014, we added 287 receipt points to our systems.

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. Operating 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 the date of 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, to 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. Pursuant to the omnibus agreement, Anadarko and the general partner perform centralized corporate functions for us. General and administrative expenses for periods prior to our acquisition of the Partnership assets include costs allocated by Anadarko in the form of a management services fee, which approximated the general and administrative costs incurred by Anadarko attributable to the Partnership assets. For periods subsequent to our acquisition of the Partnership assets, Anadarko is no longer compensated for corporate services through a management services fee. Instead, allocations and reimbursements of general and administrative expenses are determined by Anadarko in its reasonable discretion, in accordance with our partnership and omnibus agreements. Amounts required to be reimbursed to Anadarko under the omnibus agreement also 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.

See further detail under Items Affecting the Comparability of Our Financial Results – General and administrative expenses below and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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Non-GAAP financial measures

Adjusted gross margin attributable to Western Gas Partners, LP. We define Adjusted gross margin attributable to Western Gas Partners, LP (“Adjusted gross margin”) as total revenues less cost of product, plus distributions from equity investees and excluding the noncontrolling interest owners’ proportionate share of revenue and cost of product. We believe Adjusted gross margin is an important performance measure of the core profitability of our operations, as well as our operating performance as compared to that of other companies in our industry. 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 a substantial majority of 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. For a discussion of commodity price swap agreements, see Risk Factors under Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.
To facilitate investor and industry analyst comparisons between us and our peers, we also disclose Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets and Adjusted gross margin per Bbl for crude/NGL assets. See Key Performance Metrics within this Item 7.

Adjusted EBITDA attributable to Western Gas Partners, LP. We define Adjusted EBITDA attributable to Western Gas Partners, LP (“Adjusted EBITDA”) as net income attributable to Western Gas Partners, LP, plus distributions from equity investees, non-cash equity-based compensation expense, interest expense, income tax expense, depreciation, amortization and impairments, and other expense, less income from equity investments, interest income, income tax benefit, and other income. 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 (including amortization of deferred debt issuance costs originally paid in cash, offset by non-cash capitalized interest), 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 distributable cash flow to planned cash distributions. We believe Distributable cash flow 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.

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.

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Reconciliation to GAAP measures. Adjusted gross margin, Adjusted EBITDA and Distributable cash flow are not defined in generally accepted accounting principles in the United States ("GAAP"). The GAAP measure used by us that is most directly comparable to Adjusted gross margin is operating income, while net income attributable to Western Gas Partners, LP and net cash provided by operating activities are the GAAP measures used by us that are most directly comparable to Adjusted EBITDA. The GAAP measure used by us that is most directly comparable to Distributable cash flow is net income attributable to Western Gas Partners, LP. Our non-GAAP financial measures of Adjusted gross margin, Adjusted EBITDA and Distributable cash flow should not be considered as alternatives to the GAAP measures of operating income, net income attributable to Western Gas Partners, LP, net cash provided by operating activities or any other measure of financial performance presented in accordance with GAAP. Adjusted gross margin, Adjusted EBITDA and Distributable cash flow have important limitations as analytical tools because they exclude some, but not all, items that affect operating income, net income and net cash provided by operating activities. Adjusted gross margin, Adjusted EBITDA and Distributable cash flow should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Our definitions of Adjusted gross margin, 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 gross margin, Adjusted EBITDA and Distributable cash flow as analytical tools by reviewing the comparable GAAP measures, understanding the differences between Adjusted gross margin, Adjusted EBITDA and Distributable cash flow compared to (as applicable) operating income, 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.

The following tables present (a) a reconciliation of the non-GAAP financial measure of Adjusted gross margin to the GAAP measure of operating income, (b) a reconciliation of the non-GAAP financial measure of Adjusted EBITDA to the GAAP financial measures of net income attributable to Western Gas Partners, LP and net cash provided by operating activities, and (c) 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,		
thousands	2014	2013	2012
Reconciliation of Adjusted gross margin attributable to Western Gas Partners, LP to Operating income			
Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets	$822,932	$654,924	$544,853
Adjusted gross margin for crude/NGL assets	73,714	15,274	13,221
Adjusted gross margin attributable to Western Gas Partners, LP	896,646	670,198	558,074
Adjusted gross margin attributable to noncontrolling interests	20,183	17,416	20,983
Equity income, net	57,836	22,948	16,042
Less:			
Distributions from equity investees	81,022	22,136	20,660
Operation and maintenance	199,305	168,657	140,106
General and administrative	34,242	29,751	99,212
Property and other taxes	25,353	23,244	19,688
Depreciation, amortization and impairments	183,156	145,916	120,608
Operating income	$451,587	$320,858	$194,825

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thousands	Year Ended December 31, 2014	2013	2012
Reconciliation of Adjusted EBITDA attributable to Western Gas Partners, LP to Net income attributable to Western Gas Partners, LP			
Adjusted EBITDA attributable to Western Gas Partners, LP	$645,969	$457,773	$377,929
Less:			
Distributions from equity investees	81,022	22,136	20,660
Non-cash equity-based compensation expense (1)	4,095	3,575	73,508
Interest expense	76,766	51,797	42,060
Income tax expense	2,255	4,219	20,690
Depreciation, amortization and impairments (2)	180,587	143,375	118,279
Other expense (2)	—	175	1,665
Add:			
Equity income, net	57,836	22,948	16,042
Interest income – affiliates	16,900	16,900	16,900
Other income (2) (3)	325	419	368
Income tax benefit	228	1,864	—
Net income attributable to Western Gas Partners, LP	$376,533	$274,627	$134,377
Reconciliation of Adjusted EBITDA attributable to Western Gas Partners, LP to Net cash provided by operating activities			
Adjusted EBITDA attributable to Western Gas Partners, LP	$645,969	$457,773	$377,929
Adjusted EBITDA attributable to noncontrolling interests	16,583	13,348	17,214
Interest income (expense), net	(59,866)	(34,897)	(25,160)
Non-cash equity-based compensation expense (1)	(175)	(54)	(69,791)
Debt-related amortization and other items, net	2,736	2,449	2,319
Current income tax benefit (expense)	556	29,536	9,419
Other income (expense), net (3)	336	253	(1,292)
Distributions from equity investments in excess of cumulative earnings	(18,055)	(4,438)	—
Changes in operating working capital:			
Accounts receivable, net	(4,217)	(34,019)	22,916
Accounts and natural gas imbalance payables and accrued liabilities, net	(52,530)	21,952	5,045
Other	3,470	(3,702)	(552)
Net cash provided by operating activities	$534,807	$448,201	$338,047
Cash flow information of Western Gas Partners, LP			
Net cash provided by operating activities	$534,807	$448,201	$338,047
Net cash used in investing activities	(2,621,559)	(1,652,995)	