Western Gas Partners LP
Form 10-K
February 16, 2018

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, 2017

Or

¨ 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 ¨

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 ¨ 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 ¨

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 ¨

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. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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

The aggregate market value of the registrant’s common units representing limited partner interests held by non-affiliates of the registrant was $5.6 billion on June 30, 2017, based on the closing price as reported on the New York Stock Exchange.

At February 12, 2018, there were 152,602,105 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE
None

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COMMONLY USED TERMS AND DEFINITIONS

Unless the context otherwise requires, references to “we,” “us,” “our,” the “Partnership” or “Western Gas Partners, LP” refer to Western Gas Partners, LP and its subsidiaries. As used in this Form 10-K, the terms and definitions below have the following meanings:

Additional DBJV System Interest: Our additional 50% interest in the DBJV system acquired from a third party in March 2017.

AESC: Anadarko Energy Services Company.

Affiliates: Subsidiaries of Anadarko, excluding us, but including equity interests in Fort Union, White Cliffs, Rendezvous, the Mont Belvieu JV, TEP, TEG, and FRP.

AMH: APC Midstream Holdings, LLC.

AMM: Anadarko Marcellus Midstream, L.L.C.

Anadarko: Anadarko Petroleum Corporation and its subsidiaries, excluding us and our general partner.

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

Bbls/d: Barrels per day.

Board of Directors or Board: The board of directors of our general partner.

Btu: British thermal unit; the approximate amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Chipeta: Chipeta Processing, LLC.

Chipeta LLC agreement: Chipeta’s limited liability company agreement, as amended and restated as of July 23, 2009.

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 are used to bring natural gas 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.

DBJV: Delaware Basin JV Gathering LLC.

DBJV system: A gathering system and related facilities located in the Delaware Basin in Loving, Ward, Winkler and Reeves Counties in West Texas.

DBM: Delaware Basin Midstream, LLC.

DBM complex: The cryogenic processing plants, gas gathering system, and related facilities and equipment in West Texas that serve production from Reeves, Loving and Culberson Counties, Texas and Eddy and Lea Counties, New Mexico.

DBM water systems: Two produced water disposal systems in West Texas.

Delivery point: The point where hydrocarbons 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.

DJ Basin complex: The Platte Valley system, Wattenberg system and Lancaster plant, all of which were combined into a single complex in the first quarter of 2014.

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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.
EBITDA: Earnings before interest, taxes, depreciation, and amortization. For a definition of "Adjusted EBITDA," see How We Evaluate Our Operations under Part II, Item 7 of this Form 10-K.
End-use markets: The ultimate users/consumers of transported energy products.
Equity investment throughput: Our 14.81% share of average Fort Union throughput, 22% share of average Rendezvous throughput, 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.
Exchange Act: The Securities Exchange Act of 1934, as amended.
FERC: The Federal Energy Regulatory Commission.
Fort Union: Fort Union Gas Gathering, LLC.
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.
FRP: Front Range Pipeline LLC.
GAAP: Generally accepted accounting principles in the United States.
General partner: Western Gas Holdings, LLC.
Gpm: Gallons per minute, when used in the context of amine treating capacity.
Hydraulic fracturing: The injection of fluids into the wellbore to create fractures in rock formations, stimulating the production of oil or gas.
IDRs: Incentive distribution rights.
Imbalance: Imbalances result from (i) differences between gas and NGL volumes nominated by customers and gas and NGL volumes received from those customers and (ii) differences between gas and NGL volumes received from customers and gas and NGL volumes delivered to those customers.
IPO: Initial public offering.
Joule-Thompson (JT): 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.
LIBOR: London Interbank Offered Rate.
Marcellus Interest: Our 33.75% interest in the Larry's Creek, Seely and Warrensville gas gathering systems and related facilities located in northern Pennsylvania.
MBbls/d: One thousand barrels per day.
MGR: Mountain Gas Resources, LLC.
MGR assets: The Red Desert complex and the Granger straddle plant.
MIGC: MIGC, LLC.
MLP: Master limited partnership.
MMBtu: One million British thermal units.

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MMcf: One million cubic feet.
MMcf/d: One million cubic feet per day.
Mont Belvieu JV: Enterprise EF78 LLC.
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.
Non-Operated Marcellus Interest: The 33.75% interest in the Liberty and Rome gas gathering systems and related facilities located in northern Pennsylvania that was transferred to a third party in March 2017 pursuant to the Property Exchange.
NYSE: New York Stock Exchange.
NYMEX: New York Mercantile Exchange.
OTTCO: Overland Trail Transmission, LLC.
PIK Class C units: Additional Class C units issued as quarterly distributions to the holder of our Class C units.
Play: A group of gas or oil fields that contain known or potential commercial amounts of petroleum and/or natural gas.
Produced water: Byproduct associated with the production of crude oil and natural gas that often contains a number of dissolved solids and other materials found in oil and gas reservoirs.
Property Exchange: Our acquisition of the Additional DBJV System Interest from a third party in exchange for the Non-Operated Marcellus Interest and $155.0 million of cash consideration, as further described in our Forms 8-K filed with the SEC on February 9, 2017, and March 23, 2017.
RCF: Our $1.2 billion senior unsecured revolving credit facility.
Receipt point: The point where hydrocarbons are received by or into a gathering system, processing facility or transportation pipeline.
Red Desert complex: The Patrick Draw processing plant, the Red Desert processing plant, associated gathering lines, and related facilities.
Refrigeration: A method of processing natural gas by reducing the gas temperature with the use of an external refrigeration system.
Rendezvous: Rendezvous Gas Services, LLC.
Residue: The natural gas remaining after the unprocessed natural gas stream has been processed or treated.
SEC: U.S. Securities and Exchange Commission.
Springfield: Springfield Pipeline LLC.
Springfield gas gathering system: A gas gathering system and related facilities located in Dimmit, La Salle, Maverick and Webb Counties in South Texas.
Springfield oil gathering system: An oil gathering system and related facilities located in Dimmit, La Salle, Maverick and Webb Counties in South Texas.
Springfield system: The Springfield gas gathering system and Springfield oil gathering system.
Stabilization: The process of separating very light hydrocarbon gases, methane and ethane in particular, from heavier hydrocarbon components. This process reduces the volatility of the liquids during transportation and storage.

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Tailgate: The point at which processed natural gas and/or natural gas liquids leave a processing facility for end-use markets.
TEFR Interests: The interests in TEP, TEG and FRP.
TEG: Texas Express Gathering LLC.
TEP: Texas Express Pipeline LLC.
Wellhead: The point at which the hydrocarbons and water exit the ground.
WES LTIP: With respect to awards granted prior to October 17, 2017, the Western Gas Partners, LP 2008 Long-Term Incentive Plan (the "WES 2008 LTIP"), which was adopted by our general partner in connection with our IPO in 2008, and, with respect to awards granted after October 17, 2017, the Western Gas Partners, LP 2017 Long-Term Incentive Plan, which was approved by our common and Class C unitholders on October 17, 2017.
WGP: Western Gas Equity Partners, LP.
WGP GP: Western Gas Equity Holdings, LLC, the general partner of WGP.
WGP LTIP: Western Gas Equity Partners, LP 2012 Long-Term Incentive Plan.
WGRI: Western Gas Resources, Inc.
White Cliffs: White Cliffs Pipeline, LLC.
2018 Notes: Our 2.600% Senior Notes due 2018.
2021 Notes: Our 5.375% Senior Notes due 2021.
2022 Notes: Our 4.000% Senior Notes due 2022.
2025 Notes: Our 3.950% Senior Notes due 2025.
2026 Notes: Our 4.650% Senior Notes due 2026.
2044 Notes: Our 5.450% Senior Notes due 2044.
$500.0 million COP: The continuous offering program that may be undertaken pursuant to the registration statement filed with the SEC in July 2017 for the issuance of up to an aggregate of $500.0 million of our common units.

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PART I

Items 1 and 2. Business and Properties

GENERAL OVERVIEW

We are a growth-oriented Delaware MLP formed by Anadarko in 2007 to acquire, own, develop and operate midstream assets. We are engaged in the business of gathering, compressing, treating, processing and transporting natural gas; gathering, stabilizing and transporting condensate, NGLs and crude oil; and gathering and disposing of produced water. In addition, in our capacity as a processor of natural gas, we also buy and sell natural gas, NGLs or condensate under certain of our contracts. We provide these midstream services for Anadarko, as well as for third-party producers and customers. Our common units are publicly traded on the NYSE under the symbol “WES.” WGP, a Delaware MLP formed by Anadarko in September 2012, owns our general partner and a significant limited partner interest in us. WGP’s common units are publicly traded on the NYSE under the symbol “WGP.” WGP GP is a wholly owned subsidiary of Anadarko.

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 SEC under the Exchange Act. From time to time, we may also file registration and related statements pertaining to equity or debt offerings.
We provide access free of charge to all of these SEC filings, as soon as reasonably practicable after filing or furnishing such materials 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 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, 2017, our assets and investments consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Gathering systems [(1)]	12	3	3	2
Treating facilities	19	3	—	3
Natural gas processing plants/trains	20	4	—	2
NGL pipelines	2	—	—	3
Natural gas pipelines	5	—	—	—
Oil pipelines	—	1	—	1

(1) Includes the DBM water systems.

These assets and investments are located in the Rocky Mountains (Colorado, Utah and Wyoming), North-central Pennsylvania, Texas and New Mexico. The following table provides information regarding our assets by geographic region, as of and for the year ended December 31, 2017, excluding the Mentone processing plant at the DBM complex, which is currently under construction in West Texas (see Assets Under Development within these Items 1 and 2):

Area	Asset Type	Miles of Pipeline [(1)]	Approximate Number of Active Receipt Points [(1)]	Compression (HP) [(1)]	Processing or Treating Capacity (MMcf/d) [(1)]	Processing, Treating or Disposal Capacity (MBbls/d) [(1)]	Average Gathering, Processing, Treating and Transportation Throughput (MMcf/d) [(2)]	Average Gathering, Treating, Transportation and Disposal Throughput (MBbls/d) [(3)]
Rocky Mountains	Gathering, Processing and Treating	7,414	4,665	515,032	3,127	14	2,095	—
	Transportation	1,601	72	40,334	—	—	87	23
Texas / New Mexico	Gathering, Processing, Treating and Disposal	2,155	954	516,149	1,275	374	1,261	106
	Transportation	1,195	16	39,748	—	—	—	72
North-central Pennsylvania	Gathering	144	49	6,900	—	—	237	—
Total		12,509	5,756	1,118,163	4,402	388	3,680	201

(1) All system metrics are presented on a gross basis and include owned, rented and leased compressors at certain facilities. Includes horsepower associated with liquid pump stations.

(2) Includes 100% of Chipeta throughput, 50% of Newcastle throughput, 50.1% of Springfield gas gathering throughput, 22% of Rendezvous throughput and 14.81% of Fort Union throughput.

(3) Consists of throughput on the Chipeta NGL pipeline, an NGL line at the Brasada complex and at the DBM water systems, a 50.1% share of average Springfield oil gathering throughput, a 10% share of average White Cliffs throughput, a 25% share of average Mont Belvieu JV throughput, a 20% share of average TEG and TEP throughput and a 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, compressing, treating, processing and transporting natural gas; gathering, stabilizing and transporting condensate, NGLs and crude oil; and gathering and disposing of produced water. We provide these midstream services for Anadarko, as well as for third-party producers and customers in the United States. See Part II, Item 8 of this Form 10-K for disclosure of revenues, profits and total assets for the years ended December 31, 2017, 2016 and 2015.

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ACQUISITIONS AND DIVESTITURES

Property exchange. On March 17, 2017, we acquired the Additional DBJV System Interest from a third party in exchange for the Non-Operated Marcellus Interest and $155.0 million of cash consideration. We previously held a 50% interest in, and operated, the DBJV system. The Property Exchange resulted in a net gain of $125.7 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations.
See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Divestitures. During the second quarter of 2017, the Helper and Clawson systems, located in Utah, were sold to a third party, resulting in a net gain on sale of $16.3 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations.

Presentation of Partnership assets. The term "Partnership assets" includes both the assets owned and the interests accounted for under the equity method by us as of December 31, 2017 (see Note 9—Equity Investments in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K). Because Anadarko controls us through its 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 and Divestitures in the Notes to Consolidated Financial Statements under Part II, 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

Series A Preferred units. In 2016, we issued 21,922,831 Series A Preferred units to private investors. Pursuant to an agreement between us and the holders of the Series A Preferred units, 50% of the Series A Preferred units converted into common units on a one-for-one basis on March 1, 2017, and all remaining Series A Preferred units converted into common units on a one-for-one basis on May 2, 2017. See Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

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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:

- 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 infrastructure, operating expertise and customer relationships to meet new or increased demand of our services.

- Increasing third-party volumes to our systems. We 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.

- Pursuing accretive acquisitions. We expect to continue to pursue accretive acquisitions of midstream assets from Anadarko and third parties.

- Maintaining investment grade metrics. We intend to operate at appropriate leverage and distribution coverage levels in line with other partnerships in our sector that maintain investment grade credit ratings. By maintaining investment grade credit metrics, 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 our accretion and overall return.

- 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 majority of the commodity price uncertainty through the use of fee-based contracts and fixed-price hedges.

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 utilize its relationships within the energy industry and the strength of its asset portfolio to pursue projects that help to enhance the value of our business. This includes the ability of Anadarko to secure equity investment opportunities for us in connection with the commitments it makes to other midstream companies. See Our Relationship with Anadarko Petroleum Corporation below.

- Commodity price and volumetric risk mitigation. We believe our cash flows are protected from fluctuations caused by commodity price volatility due to (i) the approximately 94% of our Adjusted gross margin attributable 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 majority of our percent-of-proceeds and keep-whole contracts. For the year ended December 31, 2017, 96% of our Adjusted 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. See How We Evaluate Our Operations under Part II, Item 7 of this Form 10-K. On December 20, 2017, we renewed our commodity price swap agreements with Anadarko for the DJ Basin complex and the MGR assets through December 31, 2018. See Risk Factors under Part I, Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K. In addition, we mitigate volumetric risk by entering into contracts with cost of service structures and/or minimum volume commitments. For the year ended December 31, 2017, and excluding throughput measured in barrels, 62% of our throughput was subject to demand charges and 14% of our throughput was contracted under a cost of service model.

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- Liquidity to pursue expansion and acquisition opportunities. We believe our operating cash flows, borrowing capacity, long-term relationships and reasonable access to debt and equity capital markets provide us with the liquidity to competitively pursue acquisition and expansion opportunities and to execute our strategy across capital market cycles. As of December 31, 2017, we had $825.4 million in available borrowing capacity under the RCF.

- Substantial presence in basins with historically strong producer economics. Certain of our systems are in areas, such as the Delaware and DJ Basins, and the Eagleford shale, which have historically seen robust producer activity and are considered to have some of the most favorable producer returns for onshore North America. Our assets in these areas serve production where the hydrocarbons contain not only natural gas, but also crude oil, condensate and NGLs.

- Well-positioned and well-maintained 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 consists of high-quality, well-maintained assets for which we have implemented modern processing, treating, measurement and operating technologies.

- Consistent track record of accretive acquisitions. Since our IPO in 2008, our management team has successfully executed eleven related-party acquisitions and seven third-party acquisitions, with an aggregate acquisition value of $6.3 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, read Risk Factors under Part I, 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.

As of December 31, 2017, WGP held 50,132,046 of our common units, representing a 29.8% limited partner interest in us, and, through its ownership of our general partner, indirectly held 2,583,068 general partner units, representing a 1.5% general partner interest in us, and 100% of our IDRs. As of December 31, 2017, other subsidiaries of Anadarko collectively held 2,011,380 common units and 13,243,883 Class C units, representing an aggregate 9.1% limited partner interest in us. As of December 31, 2017, the public held 100,458,679 common units, representing the remaining 59.6% limited partner interest in us.

For the year ended December 31, 2017, production owned or controlled by Anadarko represented (i) 34% of our natural gas gathering, treating and transportation throughput (excluding equity investment throughput), (ii) 41% of our natural gas processing throughput (excluding equity investment throughput), and (iii) 56% of our crude oil, NGL and produced water gathering, treating, transportation and disposal throughput (excluding equity investment throughput). In addition, Anadarko supports our operations by providing dedications and/or minimum volume commitments with respect to a substantial portion of its throughput. In executing our growth strategy, which includes acquiring and constructing additional midstream assets, we are able to leverage Anadarko's significant industry expertise.

We have commodity price swap agreements with Anadarko to mitigate exposure to a majority of the commodity price risk inherent in our percent-of-proceeds and keep-whole contracts at the DJ Basin complex and the MGR assets. These commodity price swap agreements are set to expire in December 2018. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

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 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 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. See Risk Factors under Part I, Item 1A and Certain Relationships and Related Transactions, and Director Independence under Part III, Item 13 of this Form 10-K for more information.

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INDUSTRY OVERVIEW

The midstream industry is the link between the exploration for and production of natural gas, NGLs, and crude oil and the delivery of the resulting hydrocarbon components to end-use markets. Operators within this industry create value at various stages along the midstream value chain by gathering production from producers at the wellhead or production facility, separating the produced hydrocarbons into various components and delivering these components to end-use markets, and where applicable, gathering and disposing of produced water.
The following diagram illustrates the primary groups of assets found along the midstream value chain:

Natural Gas Midstream Services

Midstream companies provide services with respect to natural gas that are generally classified into the categories described below.

- 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 or production facilities in the area. These gathering systems transport raw, or untreated, natural gas to a central location for treating and processing, if necessary. 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. Stabilization is a process that separates the heavier hydrocarbons (which are also valuable commodities) that are sometimes 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.

- 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.

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- 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.

- Processing. The principal components of natural gas are methane and ethane, but most natural gas also contains varying amounts of heavier NGLs and contaminants, such as water and carbon dioxide, sulfur compounds, nitrogen or helium. Natural gas is processed to remove unwanted contaminants that would interfere with pipeline transportation or use of the natural gas and to separate those hydrocarbon liquids from the gas that have higher value as NGLs. The removal and separation of individual hydrocarbons through processing is possible due to differences in molecular weight, boiling point, vapor pressure and other physical characteristics.

- 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 throughout the pipeline network or at major market centers to better accommodate seasonal demand and daily supply-demand shifts. We do not currently offer storage services.

Crude Oil Midstream Services

Midstream companies provide services with respect to crude oil that are generally classified into the categories described below.

- Gathering. Crude oil gathering assets provide the link between crude oil production gathered at the well site or nearby collection points and crude oil terminals, storage facilities, long-haul crude oil pipelines and refineries. Crude oil gathering assets generally consist of a network of small-diameter pipelines that are connected directly to the well site or central receipt points and deliver into large-diameter trunk lines. To the extent there are not enough volumes to justify construction of or connection to a pipeline system, crude oil can also be trucked from a well site to a central collection point.

- Stabilization. Crude oil stabilization assets process crude oil to meet vapor pressure specifications. Crude oil delivery points, including crude oil terminals, storage facilities, long-haul crude oil pipelines and refineries, often have specific requirements for vapor pressure and temperature, and for the amount of sediment and water that can be contained in any crude oil delivered to them.

Produced Water Midstream Services

The services provided by us and other midstream companies with respect to produced water are generally classified into the categories described below.

- Gathering. Produced water often accounts for the largest byproduct stream associated with production of crude oil and natural gas. Produced water gathering assets provide the link between well sites or nearby collection points and disposal facilities.

- Disposal. As a natural byproduct of crude oil and natural gas production, produced water must be recycled or disposed of in order to maintain production. Produced water disposal systems remove hydrocarbon products and other sediments from the produced water in compliance with applicable regulations and re-inject the produced water utilizing permitted disposal wells.

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Typical Contractual Arrangements

Midstream 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, or combinations thereof, are described below:

- Fee-based. Under fee-based arrangements, the service provider typically receives a fee for each unit of (i) natural gas, NGLs, or crude oil gathered, treated, processed and/or transported, or (ii) produced water disposed of, at its facilities. As a result, the price per unit received by the service provider does not vary with commodity price changes, minimizing the service provider's direct commodity price risk exposure.

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

- Keep-whole. Keep-whole arrangements may be used for processing services. Under these arrangements, the service provider keeps 100% of the NGLs produced, and the processed natural gas, or value of the natural 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 used. 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.

See Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for information regarding recognition of revenue under 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, 2017.

GATHERING, PROCESSING AND TREATING

Overview - Rocky Mountains - Colorado and Utah

Location	Asset	Type	Processing / Treating Plants	Processing / Treating Capacity (MMcf/d)	Processing / Treating Capacity (MBbls/d)	Compressors	Compression Horsepower	Gathering Systems	Pipeline Miles
Colorado	DJ Basin complex (1)	Gathering, Processing & Treating	11	884	14	117	273,381	2	3,175
Utah	Chipeta (2)	Processing	3	790	—	12	74,875	—	2
Total			14	1,674	14	129	348,256	2	3,177

(1) The DJ Basin complex includes the Platte Valley, Fort Lupton, Fort Lupton JT, Hambert JT, which is currently inactive, and Lancaster Trains I and II processing plants; the Platteville amine treating plant; and the Wattenberg gathering system.

(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, which is currently inactive.

Rocky Mountains - Colorado

DJ Basin gathering system, treating facility and processing complex

- Customers. As of December 31, 2017, throughput at the DJ Basin complex was from Anadarko and numerous third-party customers. For the year ended December 31, 2017, Anadarko's production represented 70% of the DJ Basin complex throughput and the largest third-party customer provided 13% of the throughput.

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- Supply. There were 2,736 active receipt points connected to the DJ Basin complex as of December 31, 2017. The DJ Basin complex is primarily supplied by the Wattenberg field, in which Anadarko holds interests in over 400,000 net acres in its core position. Anadarko drilled 348 wells and completed 263 wells during the year ended December 31, 2017.

- Delivery points. As of December 31, 2017, the DJ Basin complex had the following delivery points for gas not processed within the DJ Basin complex:

Anadarko's Wattenberg plant inlet; and
Various interconnections with DCP Midstream LP's ("DCP") gathering and processing system.

The DJ Basin complex is connected to the Colorado Interstate Gas Company LLC's pipeline ("CIG pipeline") and Xcel Energy's residue pipelines for natural gas residue takeaway and to Overland Pass Pipeline Company LLC's pipeline and FRP's pipeline for NGL takeaway. In addition, the NGL fractionator at the Platte Valley plant and associated truck-loading facility provides access to local NGL markets.

Rocky Mountains - Utah

Chipeta processing complex

- Customers. As of December 31, 2017, throughput at the Chipeta complex was from Anadarko and numerous third-party customers. For the year ended December 31, 2017, Anadarko's production represented 74% of the Chipeta complex throughput and the largest third-party customer provided 15% of the throughput.

- Supply. The Chipeta complex is well positioned to access Anadarko and third-party production in the Uinta Basin where Anadarko holds interests in 238,000 gross acres. Chipeta's inlet is connected to Anadarko's Natural Buttes gathering system, the Dominion Energy Questar Pipeline, LLC system ("Questar pipeline") and Three Rivers Gathering, LLC's system, which is owned by Andeavor Logistics LP ("Andeavor").

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Delivery points. The Chipeta plant delivers NGLs to Enterprise Products Partners LP's ("Enterprise") Mid-America Pipeline Company pipeline ("MAPL pipeline"), 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 residue gas delivery points through the following pipelines delivering to markets throughout the Rockies and Western United States:

- CIG pipeline;
- Questar pipeline; and
- Wyoming Interstate Company's pipeline ("WIC pipeline").

Overview - Rocky Mountains - Wyoming

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Location	Asset	Type	Processing / Treating Plants	Processing / Treating Capacity (MMcf/d)	Compressors	Compression Horsepower	Gathering Systems	Pipeline Miles
Northeast Wyoming	Bison	Treating	3	450	9	14,620	—	—
Northeast Wyoming	Fort Union (1)	Gathering & Treating	3	295	3	5,454	1	315
Northeast Wyoming	Hilight	Gathering & Processing	2	60	38	40,443	1	1,480
Northeast Wyoming	Newcastle (1)	Gathering & Processing	1	3	6	2,660	1	189
Southwest Wyoming	Granger complex (2)	Gathering & Processing	4	520	41	43,577	1	738
Southwest Wyoming	Red Desert complex (3)	Gathering & Processing	1	125	27	51,179	1	1,113
Southwest Wyoming	Rendezvous (4)	Gathering	—	—	5	7,485	1	338
Total			14	1,453	129	165,418	6	4,173

(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 Red Desert cryogenic processing plant, which is currently inactive, and the Patrick Draw 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. Throughput at the Bison treating facility was from two third-party customers as of December 31, 2017. The largest customer provided 83% of the throughput for the year ended December 31, 2017. In connection with Anadarko's sale of its Powder River Basin coal-bed methane assets in 2015, Anadarko retained its throughput commitment to Bison through 2020.

- 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 treating facility is directly connected to Fort Union's pipeline and the Bison pipeline operated by TransCanada Corporation.

Fort Union gathering system and treating facility

- Customers. Western Gas Wyoming, L.L.C., Copano Pipelines/Rocky Mountains, LLC, Crestone Powder River LLC and Powder River Midstream, LLC hold a majority of the firm capacity on the Fort Union system. To the extent capacity on the system is not used by these customers, it is available to third parties under interruptible agreements.

- Supply. Substantially all of Fort Union's gas supply is comprised of coal-bed methane volumes that are either produced or gathered by the customers noted above and their affiliates throughout the Powder River Basin. The Fort

Union customers noted above 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:

CIG pipeline;
Tallgrass Interstate Gas Transmission system's pipeline ("TIGT pipeline"); and
WIC pipeline.

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. As of December 31, 2017, gas gathered and processed through the Hilight system was from numerous third-party customers. The three largest producers provided 74% of the system throughput for the year ended December 31, 2017.
- Supply. The Hilight gathering system serves the gas gathering needs of several conventional producing fields in Johnson, Campbell, Natrona and Converse Counties, Wyoming.
- 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 truck and rail loading facilities.

Newcastle gathering system and processing plant

- Customers. Gas gathered and processed through the Newcastle system was from numerous third-party customers as of December 31, 2017. The three largest producers provided 79% of the system throughput, with the largest producer providing 44% of the system throughput, for the year ended December 31, 2017.
- 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 intrastate pipeline for transport, distribution and sale.

Southwest Wyoming

Granger gathering system and processing complex

- Customers. Throughput at the Granger complex was from numerous third-party customers as of December 31, 2017. For the year ended December 31, 2017, 78% of the Granger complex throughput was from two third-party customers.
- Supply. The Granger complex is supplied by the Moxa Arch and the Jonah and Pinedale Anticline fields. The Granger gas gathering system had 598 active receipt points as of December 31, 2017.
- Delivery points. The residue from the Granger complex can be delivered to the following major pipelines:

CIG pipeline;
Berkshire Hathaway Energy’s Kern River pipeline (“Kern River pipeline”) via a connect with Andeavor’s Rendezvous pipeline (“Rendezvous pipeline”);
Questar pipeline;
Dominion Energy Overthrust Pipeline;
The Williams Companies, Inc.’s Northwest Pipeline (“NWPL”);
our OTTCO pipeline; and
our Mountain Gas Transportation LLC pipeline.

The NGLs have market access to the MAPL pipeline, which terminates at Mont Belvieu, Texas, as well as to local markets.

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Red Desert gathering system and processing complex

- Customers. As of December 31, 2017, throughput at the Red Desert complex was from Anadarko and numerous third-party customers. For the year ended December 31, 2017, 42% of the Red Desert complex throughput was from the two largest third-party customers and 3% was from Anadarko.
- Supply. The Red Desert complex gathers, compresses, treats and processes natural gas and fractionates NGLs produced from 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 the CIG and WIC pipelines, while NGLs are delivered to the MAPL pipeline, as well as to truck and rail loading facilities.

Rendezvous gathering system

- Customers. As of December 31, 2017, throughput on the Rendezvous gathering system was primarily from two shippers that have dedicated acreage to the system.
- Supply and delivery points. The Rendezvous gathering system provides high pressure gathering service for gas from the Jonah and Pinedale Anticline fields and delivers to our Granger plant, as well as Andeavor’s Blacks Fork gas processing plant, which connects to the Questar pipeline, NWPL and the Kern River pipeline via the Rendezvous pipeline.

Overview - Texas and New Mexico

Location	Asset	Type	Processing / Treating Plants	Processing / Treating Capacity (MMcf/d)	Processing / Treating / Disposal Capacity (MBbls/d)	Compressors / Pumps (1)	Compression Horsepower (1)	Gathering Systems	Pipeline Miles
West Texas	Haley	Gathering	—	—	—	10	15,300	1	181
West Texas / New Mexico	DBM complex (2)	Gathering, Processing & Treating	6	900	18	102	195,835	1	407
West Texas	DBJV system	Gathering & Treating	9	175	6	71	99,820	1	659
West Texas	DBM water systems	Gathering & Disposal	—	—	90	12	5,100	2	36
East Texas	Mont Belvieu JV (3)	Processing	2	—	170	—	—	—	—
South Texas	Brasada complex	Gathering, Processing & Treating	3	200	15	14	30,450	1	57
South Texas	Springfield system (4)	Gathering and Treating	3	—	75	105	169,644	2	815
Total			23	1,275	374	314	516,149	8	2,155

(1) Includes owned, rented and leased compressors and compression horsepower.
(2) Excludes 1,400 gpm of amine treating capacity at the DBM complex.

(3) We own a 25% interest in the Mont Belvieu JV, which owns two NGL fractionation trains. A third party serves as the operator.

(4) We own a 50.1% interest in the Springfield system and serve as the operator.

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West Texas / New Mexico

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Haley gathering system

- Customers. As of December 31, 2017, throughput at the Haley system was from Anadarko and two third-party producers. Anadarko's production represented 88% of the system throughput for the year ended December 31, 2017.
- Supply. Anadarko holds interests in approximately 590,000 gross (240,000 net) acres in the greater Delaware Basin, a portion of which is gathered by the Haley gathering system.
- Delivery points. The Haley gathering system provides both lean and rich gas gathering service. The lean service delivery point is into Enterprise GC, L.P.'s pipeline for ultimate delivery into Energy Transfer Partners, LP's ("ETP") Oasis pipeline (the "Oasis pipeline"). The rich service delivery point is into a high pressure gathering line, which is part of our DBJV system.

DBM gathering system, treating facility and processing complex. The DBM complex includes 900 MMcf/d of cryogenic processing capacity, 1,400 gpm of amine treating capacity and a 407-mile rich gas gathering system, which has both high and low pressure segments. See Assets Under Development within these Items 1 and 2.

- Customers. As of December 31, 2017, gas gathered and processed through the DBM complex was from Anadarko and numerous third-party customers. For the year ended December 31, 2017, 67% of the throughput was from the six largest third-party customers and 8% was from Anadarko.
- Supply. Supply of gas and NGLs for the complex comes from production from the Delaware Sands, Avalon Shale, Bone Spring and Wolfcamp formations in the Delaware Basin portion of the Permian Basin. Anadarko holds interests in approximately 590,000 gross (240,000 net) acres within the Delaware Basin.
- Delivery points. Residue gas produced at the facility is delivered to the Ramsey Residue Lines, which extend from the DBM complex to the south and to the north, with both lines connecting with Kinder Morgan, Inc.'s interstate pipeline system (see Transportation within these Items 1 and 2). NGL production is delivered into both the Sand Hills pipeline and Lone Star NGL LLC's pipeline.

DBJV gathering and treating facility. The DBJV gathering system consists of 659 miles of low pressure and high pressure gas gathering lines.

- Customers. Throughput at the DBJV system was from Anadarko and one third-party producer as of December 31, 2017. Anadarko's production represented 78% of the system throughput for the year ended December 31, 2017.
- Supply. The system gathers lean Penn gas, as well as liquids-rich Bone Spring, Avalon and Wolfcamp gas.
- Delivery points. Avalon, Bone Spring and Wolfcamp gas is dehydrated, compressed and delivered to the Bone Spring Gas Processing plant (the "Bone Spring plant"), the Mi Vida Gas Processing plant (the "Mi Vida plant") and the DBM complex for processing, while lean Penn gas is delivered into Enterprise GC, L.P.'s pipeline. Residue gas from the Bone Spring and Mi Vida plants is delivered into the Oasis pipeline or Transwestern Pipeline Company LLC's pipeline.

DBM produced water disposal systems. The DBM water systems consist of the River Reeves and Silvertip systems.

- Customers. As of December 31, 2017, throughput at the DBM water systems was from Anadarko and one third-party producer. Anadarko's production represented 93% of the throughput for the year ended December 31, 2017.

- Supply. The systems gather and dispose produced water for Anadarko and a third-party producer.

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East 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, TEP and Enterprise's Panola Pipeline, in which Anadarko has a 15% equity interest. 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 and treating facility and processing complex

- Customers. Throughput at the Brasada complex was from one third-party customer as of December 31, 2017. In the first quarter of 2017, Anadarko completed the sale of its Eagleford shale upstream assets to a third party.

- Supply. Supply of gas and NGLs comes from throughput gathered by the Springfield system.

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

Springfield gathering system, stabilization facility and storage

- Customers. Throughput at the Springfield system was from numerous third-party customers as of December 31, 2017. In the first quarter of 2017, Anadarko completed the sale of its Eagleford shale upstream assets to a third party.

- Supply. Supply of gas and oil comes from third-party production in the Eagleford shale.

- Delivery points. The gas gathering system delivers rich gas to our Brasada complex, the Raptor processing plant owned by Targa Resources Corp. and Sanchez Midstream Partners LP, and to processing plants operated by Enterprise, ETP and Kinder Morgan, Inc. The oil gathering system has delivery points to Plains All American Pipeline, Kinder Morgan, Inc.'s Double Eagle Pipeline, Hilcorp Energy Company's Harvest Pipeline and NuStar Energy L.P.'s Pipeline.

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Overview - North-central Pennsylvania

Location	Asset	Type	Compressors	Compression Horsepower	Gathering Systems	Pipeline Miles
North-central Pennsylvania	Marcellus [1]	Gathering	5	6,900	3	144

[1] We own a 33.75% interest in the Marcellus Interest gathering systems.

Marcellus gathering systems

Customers. As of December 31, 2017, the Marcellus Interest gathering systems had multiple priority shippers. The largest producer provided 75% of the throughput for the year ended December 31, 2017. Capacity not used by priority shippers is available to third parties as determined by the operating partner, Alta Resources Development, LLC. In the first quarter of 2017, Anadarko completed the sale of its operated and non-operated upstream assets and operated midstream assets (excluding our interests) in the Marcellus shale to a third party.

Supply and delivery points. The Marcellus Interest gathering systems are well positioned to serve dry gas production from the Marcellus shale. The Marcellus Interest gathering systems have access to Transcontinental Gas Pipe Line Company, LLC’s pipeline.

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TRANSPORTATION

Overview

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Location	Asset	Type	Compressors / Pump Stations	Operational Horsepower	Pipeline Miles
Colorado, Kansas, Oklahoma	White Cliffs (1) (2)	Oil	24	33,800	1,054
Utah	GNB NGL (1)	NGL	—	—	33
Northeast Wyoming	MIGC (1)	Gas	2	3,360	239
Southwest Wyoming	OTTCO	Gas	1	3,174	217
Colorado, Oklahoma, Texas	FRP (1) (3)	NGL	6	12,000	447
Texas, Oklahoma	TEG (3)	NGL	8	748	137
Texas	TEP (1) (3)	NGL	12	27,000	593
Texas	Ramsey Residue Lines (1)	Gas	—	—	18
Total			53	80,082	2,738

(1) White Cliffs, GNB NGL, MIGC, FRP, TEP and the Ramsey Residue Lines (at the DBM complex) are regulated by 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 - Colorado

White Cliffs pipeline

- Customers. The White Cliffs pipeline had multiple committed shippers, including Anadarko, as of December 31, 2017. In addition, other parties may ship on the White Cliffs pipeline at FERC-based rates. An expansion project was completed in 2017 that increased the pipeline’s capacity from 150 MBbls/d to approximately 180 MBbls/d. The White Cliffs dual pipeline system provides crude oil takeaway capacity from Platteville, Colorado to Cushing, Oklahoma.

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

- Delivery points. The White Cliffs pipeline delivery point is SemCrude’s storage facility in Cushing, Oklahoma, a major crude oil marketing center, which ultimately delivers to Gulf Coast and mid-continent refineries. At the point of origin, it has a 330,000-barrel storage facility adjacent to a truck-unloading facility.

Rocky Mountains - Utah

GNB NGL pipeline

- Customers. Anadarko was the only shipper on the GNB NGL pipeline as of December 31, 2017.

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

- Delivery points. The GNB NGL pipeline delivers NGLs to the MAPL pipeline, 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 - Northeast Wyoming

MIGC transportation system

- Customers. Anadarko was the largest firm shipper on the MIGC system, with 88% of the throughput for the year ended December 31, 2017. The remaining throughput on the MIGC system was from numerous third-party shippers. MIGC is certificated for 175 MMcf/d of firm transportation capacity.

- Supply. MIGC receives gas from various coal-bed methane gathering systems in the Powder River Basin and the Hilight system, as well as from WBI Energy Transmission, Inc. on the north end of the transportation system.

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

CIG pipeline;
TIGT pipeline; and
WIC pipeline.

Volumes can also be delivered to Cheyenne Light Fuel & Power and several industrial users.

Rocky Mountains - Southwest Wyoming

OTTCO transportation system

- Customers. For the year ended December 31, 2017, 10% 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 contracts that contain minimum volume commitments and volumetric fees paid by shippers under firm and interruptible gas transportation agreements.

- Supply and delivery points. Supply points to the OTTCO transportation system include approximately 50 wellheads, 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 inactive interconnection with the Kern River pipeline.

Texas

TEFR Interests

- Front Range Pipeline. FRP provides takeaway capacity from the DJ Basin in Northeast Colorado. FRP has receipt points at gas plants in Weld County, Colorado (including the Lancaster plant, which is within the DJ Basin complex) (see Rocky Mountains—Colorado and Utah within these Items 1 and 2). FRP connects to TEP near Skellytown, Texas. As of December 31, 2017, FRP had multiple committed shippers, including Anadarko. FRP provides capacity to 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 as of December 31, 2017.

- 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 the MAPL pipeline. As of December 31, 2017, TEP had multiple committed shippers, including Anadarko. TEP provides capacity to other shippers at the posted FERC tariff rates.

Ramsey Residue Lines. The Ramsey Residue Lines extend from the DBM complex to the south and to the north, with both lines connecting with Kinder Morgan, Inc.'s interstate pipeline system. These lines transport residue gas from the DBM complex to interstate markets and are FERC-regulated pipelines. See DBM gathering system, treating facility and processing complex within these Items 1 and 2.

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Assets Under Development

In addition to significant gathering expansion projects at both the DBJV system and DJ Basin complex, we currently have the following significant projects scheduled for completion in 2018 and 2019 in West Texas and Colorado. See Capital expenditures, under Part II, Item 7 of this Form 10-K.

- Mentone processing plant: We are currently constructing two cryogenic processing trains at a new processing plant located in Loving County, Texas. Mentone Trains I and II will each have a capacity of 200 MMcf/d and we expect these trains to be completed during the third and fourth quarters of 2018, respectively. The Mentone processing plant will be part of the DBM complex, and upon completion of Mentone Trains I and II, the DBM complex will have a total processing capacity of 1,300 MMcf/d.

- Latham processing plant: We have sanctioned two cryogenic processing trains at a new processing plant located in Weld County, Colorado. Construction of Latham Trains I and II (each with a capacity of 200 MMcf/d) is expected to begin by the third quarter of 2018 and we expect these trains to be completed during the first and third quarters of 2019, respectively. The Latham processing plant will be part of the DJ Basin complex, and upon completion of Latham Trains I and II, the DJ Basin complex will have a total processing capacity of 1,250 MMcf/d.

COMPETITION

The midstream services business is extremely competitive. Our competitors include other midstream companies, producers, and intrastate and interstate pipelines. Competition is primarily based on reputation, commercial terms, reliability, service levels, location, available capacity, capital expenditures and fuel efficiencies. However, Anadarko supports our operations by providing dedications and/or minimum volume commitments with respect to a substantial portion of its throughput. We believe that our assets 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 efficiently, and at competitive and flexible contract terms, provide services that producers and other customers require to connect, gather and process their natural gas, and gather and dispose of their produced water.

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Gathering Systems and Processing Plants

The following table summarizes the primary competitors for our gathering systems and processing plants as of December 31, 2017.

Asset	Competitor(s)
Bison facility	Thunder Creek Gas Services, LLC and Fort Union (treating only)
Brasada complex	Enterprise, ETP, Targa Resources Partners LP, Kinder Morgan, Inc., Plains All American Pipeline and Howard Energy Partners
Chipeta complex	Andeavor and Kinder Morgan, Inc.
DBJV system	ETP, Targa Resources Partners LP, Enterprise GC, L.P., EagleClaw Midstream Ventures, LLC, Enlink Midstream Partners, LP and Vaquero Midstream LLC
DBM complex	ETP, Targa Resources Partners LP, Enterprise GC, L.P., EagleClaw Midstream Ventures, LLC, Enlink Midstream Partners, LP, Vaquero Midstream LLC, MPLX LP, Crestwood Midstream Partners LP and Noble Midstream Partners LP
DBM water systems	NGL Water Solutions, LLC, Mesquite SWD, Inc. and Oilfield Water Logistics, LLC
DJ Basin complex	DCP, AKA Energy Group, LLC and Discovery Midstream Partners
Fort Union system	Bison treating facility (carbon dioxide treating services only), MIGC, Thunder Creek Gas Services, LLC and TransCanada Corporation
Granger complex	Williams Field Services Company, LLC, Enterprise/Jonah Gas Gathering Company and Andeavor
Haley system	ETP, Targa Resources Partners LP and Enterprise GC, L.P.
Hilight system	ONEOK Gas Gathering Company, Thunder Creek Gas Services, LLC, Crestwood-Access, Tallgrass Energy Partners, LP and Evolution Midstream
Marcellus Interest gathering systems	ETP and National Fuel Gas Midstream Corporation
Mont Belvieu JV	Targa Resources Partners LP, Phillips 66, Lone Star NGL LLC and ONEOK Partners, LP
Newcastle system	Tallgrass Energy Partners, LP
Red Desert complex	Williams Field Services Company, LLC and Andeavor
Rendezvous system	No significant direct competition
Springfield system	Enterprise, ETP, Targa Resources Partners LP, Kinder Morgan, Inc., Plains All American Pipeline, Southcross Energy Partners, L.P., Williams Field Services Company, LLC and Howard Energy Partners

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 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 and the Fort Union gathering system. The GNB NGL pipeline's major competitor is Andeavor. The White Cliffs pipeline faces direct competition from the Saddlehorn pipeline, of which Anadarko is a 20% owner, and the Grand Mesa pipeline. The Saddlehorn pipeline transports crude oil from the DJ Basin and the broader Rocky Mountain area to Cushing, Oklahoma. White Cliffs pipeline shippers can also sell crude oil in local markets or ship crude oil via rail services rather than via pipeline to Cushing, Oklahoma. The TEFR Interests compete with the Sand Hills pipeline, West Texas LPG Pipeline LP's pipeline, Lone Star NGL LLC's West Texas System, Overland Pass Pipeline Company LLC's pipeline and the Seminole pipeline. The OTTCO transportation system faces no direct competition. The Ramsey Residue Lines face competition from ETP, Enterprise and Kinder Morgan, Inc.

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REGULATION OF OPERATIONS

Safety and Maintenance

Many of the pipelines we use to gather and transport oil, natural gas and NGLs are subject to regulation by the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), an agency under the U.S. Department of Transportation 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 and oil. The NGPSA and HLPSA govern the design, installation, testing, construction, operation, replacement and management of natural gas, crude oil, NGL and condensate pipeline facilities. Pursuant to these acts, PHMSA has promulgated regulations governing, among other things, pipeline wall thicknesses, design pressures, maximum allowable operating pressures ("MAOP"), 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 ("HCAs"), where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources and unusually sensitive ecological areas. Past operation of our pipelines with respect to these NGPSA and HLPSA requirements has not resulted in the incurrence of material costs; however, due to the possibility of new or amended laws and regulations or reinterpretation of PHMSA enforcement practices or other guidance with respect thereto, future compliance with the NGPSA and HLPSA could result in increased costs that could have a material adverse effect on our results of operations or financial position.

The NGPSA and HLPSA were amended by the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (the "2011 Pipeline Safety Act"), which increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. In June 2016, the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (the "2016 Pipeline Safety Act") extended PHMSA's statutory mandate through 2019 and, among other things, empowered PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities without prior notice or an opportunity for a hearing. PHMSA published an interim final rule in October 2016 to implement the agency's expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property or the environment.

The adoption of new or amended regulations by PHMSA that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on our results of operations. For example, in January 2017, PHMSA issued a final rule that significantly extends and expands the reach of certain PHMSA hazardous liquid pipeline integrity management requirements, such as, for example, periodic assessments, leak detection and repairs, regardless of the pipeline's proximity to a high consequence area. The final rule also imposes new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. However, the date of implementation of this final rule by publication in the Federal Register remains uncertain following the January 2017 change in presidential administrations. Additionally, in March 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain gas transportation and gathering lines including, among other things, expanding certain of PHMSA's current regulatory safety programs for gas pipelines in newly defined "moderate consequence areas" that contain as few as five dwellings within a potential impact area; requiring gas pipelines installed before 1970 and thus excluded from certain pressure testing obligations to be tested to determine their MAOP; and requiring certain onshore and offshore gathering lines in Class I areas to comply with damage prevention, corrosion control, public education, MAOP limits, line markers and emergency planning standards. Additional requirements proposed by this proposed rulemaking would increase PHMSA's integrity management requirements for gas pipelines and also require consideration of seismicity in evaluating threats to pipelines. PHMSA has not yet finalized the March 2016 proposed rulemaking. New laws or regulations adopted by

PHMSA may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased capital and operating costs and operational delays. 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. Historically, our intrastate pipeline safety compliance costs have not had a material adverse effect on our operations; however, there can be no assurance that such costs will not be material in the future.

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We are also subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended, and comparable state statutes, the purposes of which are to protect the health and safety of workers, both generally and within the pipeline industry. Furthermore, we and the entities in which we own an interest are subject to regulations imposed by the Occupational Safety and Health Administration ("OSHA") that (i) require information to 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 and (ii) are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. See Risk Factor, "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" under Part I, Item 1A of this Form 10-K for further discussion on pipeline safety standards.

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 operations of our MIGC pipeline and the Ramsey Residue Lines 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.

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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. In July 2016, the United States Court of Appeals for the District of Columbia Circuit issued its opinion in United Airlines, Inc., et al. v. FERC, finding that FERC had acted arbitrarily and capriciously when it failed to demonstrate that permitting an interstate petroleum products pipeline organized as a limited partnership to include an income tax allowance in the cost of service underlying its rates in addition to the discounted cash flow return on equity would not result in the pipeline partnership owners double-recovering their income taxes. The court vacated FERC's order and remanded to FERC to consider mechanisms for demonstrating that there is no double recovery as a result of the income tax allowance. FERC has also initiated a notice of inquiry regarding its policy for recovery of income tax costs, which remains ongoing. There is not likely to be a definitive resolution of these issues for some time, and the ultimate outcomes of these proceedings are not certain and could result in changes going forward to the FERC's treatment of income tax allowances in the cost of service or to the discounted cash flow return on equity. Depending upon the resolution of these issues, the cost of service rates of our FERC-regulated interstate pipelines could be affected to the extent new rates or changes to its existing rates are proposed, or if any such rates are subject to complaint or challenged by the FERC, which could cause the rates and revenues for our FERC-regulated pipelines to be adversely affected.

Interstate natural gas pipelines regulated by FERC are also 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 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 engage in fraudulent conduct. The Commodity Futures Trading Commission (the "CFTC") also holds authority to monitor certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act. FERC and CFTC have authority to impose civil penalties for violations of these statutes and regulations potentially in excess of $1.0 million per day per violation. Should we fail to comply with all applicable statutes, rules, regulations and orders administered by FERC and CFTC, we could be subject to substantial penalties and fines.

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 GNB NGL pipeline provides interstate service as a FERC-regulated common carrier under the Interstate Commerce Act, the Energy Policy Act of 1992, and related rules and orders. We also own interests in FRP, TEP, and White Cliffs, each of which provides interstate services as a FERC-regulated common carrier. 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 July 2, 2016, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23%. 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.

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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 pending an investigation. 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. Finally, the outcome of the FERC policy regarding income tax allowance described above would also apply to our pipelines regulated under the Interstate Commerce Act.

As discussed above, the CFTC holds authority to monitor certain segments of the physical and futures energy commodities market. The Federal Trade Commission (the "FTC") has authority to monitor petroleum markets in order to prevent market manipulation. The CFTC and FTC have authority to impose civil penalties for violations of these statutes and regulations potentially in excess of $1.0 million per day per violation. Should we fail to comply with all applicable statutes, rules, regulations and orders administered by the CFTC and FTC, we could be subject to substantial penalties and fines.

Natural Gas Gathering Pipeline Regulation

Regulation of gas gathering pipeline services may affect certain aspects of our business and the market for our products and services. Natural gas gathering facilities are exempt from the jurisdiction of FERC. We believe that our gas gathering pipelines meet the traditional tests that FERC has used to determine that a pipeline is not subject to FERC jurisdiction, although FERC has not made any determinations with respect to the jurisdictional status of any of our gas pipelines other than MIGC and the Ramsey Residue Lines. The distinction between FERC-regulated gas 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. Our natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services. Our natural gas gathering operations also may be or become subject to additional safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

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

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 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. FERC’s civil penalty authority, described above, would apply to violations of these rules.

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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 pipeline operators 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.
In the event any of our intrastate pipelines offer natural gas transportation services under Section 311 of the Natural Gas Policy Act of 1978, 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, described above, 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, read Risk Factors under Part I, Item 1A of this Form 10-K for more information.

ENVIRONMENTAL MATTERS

Our business operations are subject to numerous federal, regional, state, tribal, and local environmental laws and regulations. The more significant of these existing environmental laws and regulations include the following U.S. laws and regulations, as amended from time to time:

- the Clean Air Act, which restricts the emission of air pollutants from many sources and imposes various pre-construction, monitoring, and reporting requirements, and which the U.S. Environmental Protection Agency (the “EPA”) has relied upon as authority for adopting climate change regulatory initiatives relating to greenhouse gas (“GHG”) emissions;

- the Federal Water Pollution Control Act, also known as the Federal Clean Water Act, which regulates discharges of pollutants from facilities to state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemakings as protected waters of the United States;

- the Oil Pollution Act of 1990, which subjects owners and operators of onshore facilities and pipelines to liability for removal costs and damages arising from an oil spill in waters of the United States;

- the Comprehensive Environmental Response, Compensation and Liability Act of 1980, which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;

- the Resource Conservation and Recovery Act, which governs the generation, treatment, storage, transport, and disposal of solid wastes, including hazardous wastes;

- the Safe Drinking Water Act, which regulates the quality of the nation’s public drinking water through adoption of drinking water standards and control over the injection of waste fluids into below-ground formations that may adversely affect drinking water sources;

- the Emergency Planning and Community Right-to-Know Act, which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees, and response departments on toxic chemical uses and inventories;

- the Endangered Species Act, which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas;

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- the National Environmental Policy Act, which requires federal agencies to evaluate major agency actions having the potential to impact the environment and that may require the preparation of Environmental Assessments and more detailed Environmental Impact Statements that may be made available for public review and comment; and

- U.S. Department of Transportation regulations, which relate to advancing the safe transportation of energy and hazardous materials and emergency preparedness.

These laws and their implementing regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water, and disposals or other releases to surface and below-ground soils and ground water. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the permitting, development or expansion of projects; and the issuance of injunctions restricting or prohibiting some or all of our activities in a particular area. See the following risk factors under Part I, Item 1A of this Form 10-K for further discussion on ozone standards, climate change, including methane or other GHG emissions, hydraulic fracturing and other regulations related to environmental protection: “We are subject to stringent and comprehensive environmental laws and regulations that may expose us to significant costs and liabilities,” “The adoption of climate change or other air emissions legislation or regulations restricting emissions of GHGs or other air pollutants could result in increased operating costs and reduced demand for the gathering, processing, compressing, treating and transporting services we provide,” and “Changes in laws or regulations regarding hydraulic fracturing could result in increased costs, operating restrictions or delays in the completion of oil and natural gas wells, which could decrease the need for our gathering and processing services.” The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as existing standards are subject to change and new standards continue to evolve. Many states where we operate also have, or are developing, similar environmental laws and regulations governing many of these same types of activities. While the legal requirements imposed under state law may be similar in form to federal laws and regulations, in some cases the actual implementation of these requirements may impose additional, or more stringent, conditions or controls that can significantly alter or delay the permitting, development or expansion of a project or substantially increase the cost of doing business. In addition, environmental laws and regulations, including new or amended legal requirements that may arise to address potential environmental concerns including air and water impacts, are expected to continue to have a considerable impact on our operations.

We have incurred and will continue to incur operating and capital expenditures, some of which may be material, to comply with environmental and occupational health and safety laws and regulations. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not have a material adverse effect on our business, financial condition, results of operations, or cash flows in the future, or that new or more stringently applied existing laws and regulations will not materially increase the cost of doing business. Although we are not fully insured against all environmental and occupational health and safety risks, and our insurance does not cover any penalties or fines that may be issued by a governmental authority, we maintain insurance coverage that we believe is sufficient based on our assessment of insurable risks and consistent with insurance coverage held by other similarly situated industry participants. Nevertheless, it is possible that other developments, such as stricter and more comprehensive environmental and occupational health and safety laws and regulations, as well as claims for damages to property or persons or imposition of penalties resulting from our operations, could have a material adverse effect on us and our results of operations.

In addition, we dispose of produced water generated from oil and natural gas production operations. The legal requirements related to the disposal of produced water in underground injection wells are subject to change based on concerns of the public or governmental authorities, including concerns relating to recent seismic events near injection wells used for the disposal of produced water. In response to such concerns, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or are otherwise investigating the existence of a relationship between seismicity and the use of such wells. In addition, ongoing class action lawsuits, to which we are not currently a party, allege that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on our use of injection wells to dispose of produced water, which could have a material adverse effect on our results of operations, capital expenditures and operating costs, and financial condition.

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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 title 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 is held by us pursuant to surface leases between us, as lessee, and the fee owner of the lands, as lessor. 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 was a governmental entity. We believe we have 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 the 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

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, 2017, Anadarko employed 438 people who provided direct support to our field operations. All of these employees are deemed jointly employed by Anadarko and our general partner under the services and secondment agreement between our general partner and Anadarko. None of these employees are covered by collective bargaining agreements, and Anadarko considers its employee relations to be good. We have separately contracted with Anadarko under the omnibus agreement for general and administrative support for our operations.

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Item 1A. Risk Factors

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

We have made in this Form 10-K, and may from time to time 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 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 price of, oil, natural gas, NGLs and related products or services;
- our ability to mitigate exposure to the commodity price risks inherent in our percent-of-proceeds and keep-whole contracts through the extension of our commodity price swap agreements with Anadarko, or otherwise;
- weather and natural disasters;
- inflation;
- the availability of goods and services;
- general economic conditions, internationally, 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;
- the creditworthiness of Anadarko or our other counterparties, including financial institutions, operating partners, and other parties;
- changes in Anadarko's capital program, strategy or desired areas of focus;
- our commitments to capital projects;
- our ability to use the RCF;
- our ability to repay debt;
- 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 from Anadarko or third parties, and Anadarko's ability to generate an inventory of assets suitable for acquisition;
- non-payment or non-performance of Anadarko or other significant customers, including under our gathering, processing, transportation and disposal agreements and our $260.0 million note receivable from Anadarko;
- the timing, amount and terms of future issuances of equity and debt securities;
- the outcome of pending and future regulatory, legislative, or other proceedings or investigations, including the investigation by the National Transportation Safety Board ("NTSB") related to Anadarko's operations in Colorado, and continued or additional disruptions in operations that may occur as Anadarko and we comply with regulatory orders or other state or local changes in laws or regulations in Colorado; and
- other factors discussed below and elsewhere in this Item 1A, under the caption Critical Accounting Estimates included under Part II, Item 7 of this Form 10-K, and in our other public filings and press releases.

The risk factors and other factors noted throughout this Form 10-K 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 portion of the natural gas, crude oil, NGLs and produced water that we gather, treat, process, transport and/or dispose. 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 portion of the natural gas, crude oil, NGLs and produced water that we gather, treat, process, transport and/or dispose. For the year ended December 31, 2017, production owned or controlled by Anadarko represented (i) 34% of our natural gas gathering, treating and transportation throughput (excluding equity investment throughput), (ii) 41% of our natural gas processing throughput (excluding equity investment throughput), and (iii) 56% of our crude oil, NGL and produced water gathering, treating, transportation and disposal throughput (excluding equity investment throughput). Anadarko may decrease its production 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 determine that drilling activity in areas other than our 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 controlling party 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 controlling party of our general partner and we expect to derive a 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 oil and natural gas prices, which could have a negative effect on the value of Anadarko's oil and natural gas properties, its drilling programs and its ability to finance its operations;

- the availability of capital on favorable terms 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 its oil and natural gas reserves;

- Anadarko's operations in foreign countries, which are subject to political, economic and other uncertainties;

- Anadarko's drilling, flowline, pipeline, and operating risks, including potential environmental liabilities;

- transportation capacity constraints and interruptions;

- adverse effects of governmental and environmental regulation;
- shareholder activism with respect to Anadarko’s stock or activities by non-governmental organizations to restrict the exploration, development and production of oil and natural gas by Anadarko; 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 further, 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. 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 on 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.

See Part I, Item 1A in Anadarko's Form 10-K for the year ended December 31, 2017 (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.

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

Sustained low natural gas, NGL or 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 have declined substantially from the highs achieved in 2008 and have remained depressed for several years. More recently, uncertain global demand for crude oil and the increased supply resulting from the rapid development of shale plays throughout North America have contributed significantly to a substantial drop in crude oil prices. Rapid development of the North American shale plays has also increased the supply of natural gas contributing to a substantial drop in natural gas prices. 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;
- the availability of transportation systems with adequate capacity;

- the volatility and uncertainty of regional pricing differentials, such as in the Rocky Mountains;
- the price and availability of alternative fuels;

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- 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, oil, natural gas, NGLs and other commodities.

We generate distributable cash flow from the above-market component of commodity price swap agreements with Anadarko that are scheduled to expire on December 31, 2018.

As discussed in more detail in Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K, for the year ended December 31, 2017, we had commodity price swap agreements in place with Anadarko related to our activities at the DJ Basin complex and MGR assets at prices that were significantly higher than those that could have been obtained from third parties on the open market. The above-market component of this swap activity is recorded as a cash contribution from Anadarko in the period in which attributable volumes are settled, with all such contributions included in our calculation of distributable cash flows. During 2017, for example, we recorded $58.6 million in cash contributions from Anadarko related to these swaps.
On December 20, 2017, we renewed our commodity price swap agreements with Anadarko for the DJ Basin complex and the MGR assets at significantly higher prices than those that could have been obtained from third parties on the open market. These swap agreements expire on December 31, 2018.
We may be unable to further renew the swaps with Anadarko for the DJ Basin complex and the MGR assets 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 is likely to be significantly less favorable from a commodity pricing perspective and would likely result in a significant decrease in our distributable cash flow.

Because of the natural decline in production from existing wells, our success depends on our ability to obtain new sources of oil and natural gas, which is dependent on certain factors beyond our control. Any decrease in the volumes 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 and oil wells connected to our gathering systems and processing and treating 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 oil and natural gas. The primary factors affecting our ability to obtain sources of oil and 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 oil and natural gas reserves. Declines in oil and natural gas prices have materially reduced exploration, development and production activity in some regions and, if sustained, could lead to a further 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 oil and 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.

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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 distributions at previously announced levels to holders of our common units.

In order to pay the announced fourth quarter 2017 distribution of $0.920 per unit per quarter, or $3.680 per unit per year, we will require available cash of $216.6 million per quarter, or $866.3 million per year, based on the number of common units, general partner units and IDRs outstanding at February 1, 2018. We may not have sufficient available cash from operating surplus each quarter to enable us to pay distributions at current levels. 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 oil and natural gas;
- the volume of oil and natural gas we gather, compress, process, treat and/or 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 companies;
- regulatory action affecting the supply of or demand for oil or natural gas, the rates we can charge, how we contract for services, our existing contracts, our operating costs or our operating flexibility; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, 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.

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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, 2017, 6% of our Adjusted 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, crude oil and NGLs. This percentage may significantly increase as a result of future acquisitions, if any. See How We Evaluate Our Operations under Part II, Item 7 of this Form 10-K.
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 in December 2018 to manage a 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 20, 2017, we renewed our commodity price swap agreements with Anadarko for the DJ Basin complex and the MGR assets through December 31, 2018. Upon the expiration of these commodity price swap agreements, 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 is likely to be significantly 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.

Changes in laws or regulations regarding hydraulic fracturing could result in increased costs, operating restrictions or delays in the completion of oil and natural 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. Hydraulic fracturing is an essential and common practice used by many of our oil and natural gas exploration and production customers to stimulate production of natural gas and oil from dense subsurface rock formations such as shales. Hydraulic fracturing is typically regulated by state oil and natural-gas commissions, but, in recent years, several federal agencies have also asserted regulatory authority over and proposed or promulgated regulations governing certain aspects of the process. For example, in June 2016, the EPA published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants.
Additionally, in Colorado, where 28% of our throughput for natural gas assets (excluding equity investment throughput) is generated, certain interest groups opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have from time to time pursued ballot initiatives that, if approved, would allow revisions to the state constitution in a manner that would make such exploration and production more difficult or costly in the future. Furthermore, Congress has from time to time considered the adoption of legislation to provide for federal regulation of hydraulic fracturing. At the state level, a growing number of states have adopted or are considering adopting legal requirements that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations, and states could elect to prohibit high-volume hydraulic fracturing altogether, following the

approach taken by the State of New York. In addition, 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, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under some circumstances.”

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If new or more stringent federal, state or local legal restrictions or prohibitions relating to the hydraulic fracturing process are adopted in areas where our oil and natural gas exploration and production customers operate, those customers could incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of exploration, development or production activities, which could reduce demand for our gathering and processing services. Moreover, increased regulation of the hydraulic fracturing process could also lead to greater opposition to, and litigation over, oil and natural gas production activities using hydraulic fracturing techniques.

Regulations relating to potential induced seismic activity associated with produced water disposal could affect our operations.

We dispose of produced water generated from oil and natural gas production operations. The legal requirements related to the disposal of produced water in underground injection wells are subject to change based on concerns of the public or governmental authorities, including concerns relating to recent seismic events near injection wells used for the disposal of produced water. In response to such concerns, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or are otherwise investigating the existence of a relationship between seismicity and the use of such wells. For example, Colorado developed and follows guidance when issuing underground injection control permits to limit the maximum injection pressure, rate, and volume of water. Oklahoma has issued rules for wastewater disposal wells that imposed certain permitting and operating restrictions and reporting requirements on disposal wells in proximity to faults, and is also developing and implementing plans directing certain wells where seismic incidents have occurred to restrict or suspend disposal well operations. The Texas Railroad Commission has also adopted similar permitting, operating, and reporting rules for disposal wells. In addition, ongoing class action lawsuits, to which we are not currently a party, allege that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on our use of injection wells to dispose of produced water, which could have a material adverse effect on our results of operations, capital expenditures and operating costs, and financial condition.

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.

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 make may reduce, rather than increase, our cash generated from operations on a per-unit basis or otherwise fail to meet our expectations.

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 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 because, among other things, (i) we are unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts, (ii) we are unable to

obtain financing for these acquisitions on economically acceptable terms, (iii) we are outbid by competitors, including as a result of increases in our overall cost of capital resulting from our capital structure, or (iv) Anadarko lacks assets suitable for us to acquire, 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.

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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.

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 the oil and gas industry. The repricing of credit risk and the recent 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 the 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 publicly traded notes (collectively, 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 agreements governing the Notes, the RCF and any future financing arrangements 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;

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- make any material change to the nature of our business from the midstream 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 EBITDA, as defined in the RCF, 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 Part II, Item 7 of this Form 10-K for a further discussion of the terms of the RCF and Notes.

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 the 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.

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Our failure to maintain an adequate system of internal control over financial reporting could adversely affect our ability to accurately report our results.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is designed to provide a reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with GAAP. A material weakness is a deficiency, or a combination of deficiencies, in our internal control that results in a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. Effective internal control is necessary for us to provide reliable financial reports and deter and detect any material fraud. If we cannot provide reliable financial reports or prevent material fraud, our reputation and operating results will be harmed. Our efforts to develop and maintain our internal control and to remediate material weaknesses in our control may not be successful, and we may be unable to maintain adequate control over our financial processes and reporting in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective control, or difficulties encountered in their implementation or other effective improvement of our internal control, could harm our operating results. Ineffective internal control could also cause investors to lose confidence in our reported financial information.

Our business could be negatively affected by security threats, including cyber threats, and other disruptions.

We face various security threats, including cyber threats to the security of our facilities and infrastructure, attempts to gain unauthorized access to sensitive information or to render data or systems unusable and terrorist acts. Our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our facilities, infrastructure and information may result in increased costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. Cyber attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software intended to gain unauthorized access to data and systems, electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. For example, the gathering, processing, treating and transportation of natural gas from our gathering systems, processing facilities and pipelines are dependent on communications among our facilities and with third-party systems that may be delivering natural gas into or receiving natural gas and other products from our facilities. Disruption of those communications, whether caused by cyber attacks or otherwise, may disrupt our ability to deliver natural gas and control these assets.
There is no assurance that we will not suffer material losses from cyber attacks in the future, and as such threats continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate or remediate any cyber vulnerabilities. Any terrorist or cyber attack against, or other disruption of, our assets or computer systems could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

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, 2017, on all of our common units, general partner units and IDRs was $216.6 million, or $866.3 million per year. The Class C unit distribution, if paid in cash, would have been $12.2 million for the quarter ended December 31, 2017. To the extent we do not have sufficient available cash under our partnership agreement, we may be unable to pay such

distributions or similar distributions in the future.

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We typically do not obtain independent evaluations of hydrocarbon reserves connected to our systems. Therefore, in the future, throughput on our systems could be less than we anticipate.

We typically do not obtain independent evaluations of hydrocarbon 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 oil and 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 commodity prices 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 a substantial portion 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. For example, see the discussion of material impairments at our Hilight system and Red Desert and Granger complexes in Note 7—Property, Plant and Equipment in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.
Further, at December 31, 2017, we had $416.2 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, such as our inability to maintain throughput on our assets or sustained lower oil and natural gas prices, by reducing the fair value of the associated reporting unit. Prolonged low or further declines in commodity prices and changes to producers' drilling plans in response to lower prices could result in additional impairments in future periods. 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 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 crude oil, 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. If we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. FERC has civil penalty authority to impose penalties for certain violations potentially in excess of $1.0 million per day for each violation. FERC also has the power to order disgorgement of profits from transactions deemed to violate applicable statutes. For additional information, read Regulation of Operations–Interstate Natural Gas Pipeline Regulation under Items 1 and 2 of this Form 10-K.
Our interstate liquids pipelines are common carriers and are also subject to regulation by FERC. 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. For additional information, read Regulation of Operations–Interstate Liquids Pipeline Regulation under Items 1 and 2 of this Form 10-K.

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 gas gathering systems meet the traditional tests FERC has used to determine if a pipeline is a gas 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 gas 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 gas 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. For additional information, read Regulation of Operations–Natural Gas Gathering Pipeline Regulation under Items 1 and 2 of this Form 10-K.

The adoption of climate change or other air emissions legislation or regulations restricting emissions of GHGs or other air pollutants could result in increased operating costs and reduced demand for the gathering, processing, compressing, treating and transporting services we provide.

Changes in climate change or other air emissions laws and regulations, or reinterpretations of enforcement or other guidance with respect thereto, that govern areas where we operate may negatively impact our operations. Examples of such proposed and/or final regulations or other regulatory initiatives are included below.

- Ground-Level Ozone Standards. In October 2015, the EPA issued a rule under the Clean Air Act, lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone from 75 parts per billion to 70 parts per billion. The EPA published a final rule in November 2017 that issued attainment or unclassifiable area designations with respect to ground-level ozone for numerous counties in the United States and is expected to issue non-attainment area designations in the first half of 2018. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Also, states with counties that are designated as non-attainment are expected to implement more stringent regulations for those non-attainment areas, which could require installation of new emission controls on some of our equipment, resulting in longer permitting timelines, and significantly increase our capital expenditures and operating costs.

- Reduction of Methane Emissions by the Oil and Gas Industry. In June 2016, the EPA published a final rule establishing new emissions standards for methane and additional standards for volatile organic compounds from certain new, modified, and reconstructed oil and natural gas production and natural gas processing and transmission facilities. The EPA's rule is comprised of New Source Performance Standards, known as Subpart OOOOa, which require certain new, modified, or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand previously issued New Source Performance Standards to, among other things, hydraulically fractured oil and natural gas well completions, fugitive emissions from well sites and compressors, and equipment leaks at natural gas processing plants and pneumatic pumps. However, in June 2017, the EPA published a proposed rule to stay certain portions of these Subpart OOOOa standards for two years and revisit the entirety of the 2016 standard, but it has not yet published a final rule and, as a result, the June 2016 standards remain in effect but future implementation of the 2016 standards is uncertain at this time. Furthermore, the Bureau of Land Management ("BLM") published a final rule in November 2016 that requires a reduction in methane emissions from venting, flaring and leaking on public lands. However, in December 2017, the BLM published a final rule that temporarily suspends or delays certain requirements contained in the 2016 final rule until January 17, 2019. The suspension of the November 2016 final rule is being challenged by several non-governmental organizations and states. Notwithstanding the current uncertainty of the 2016 rule, we have taken measures to enter into a voluntary regime, together with certain other oil and natural gas exploration and production operators, to reduce methane emissions. At the state level, some states where we operate, including Colorado, have issued requirements for the performance of leak detection programs that identify and repair methane leaks at certain oil and natural gas sources. Compliance with these rules or with any future federal or state methane regulations could, among other things, require installation of new emission controls on some of our equipment and significantly increase our capital expenditures and operating costs.

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- Reduction of GHG Emissions. The U.S. Congress and the EPA, in addition to some state and regional authorities, have in recent years considered legislation or regulations to reduce emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. In the absence of federal GHG-limiting legislation, the EPA has determined that GHG emissions present a danger to public health and the environment and has adopted regulations that, among other things, restrict emissions of GHGs under existing provisions of the Clean Air Act and may require the installation of "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they would otherwise emit large volumes of GHGs together with other criteria pollutants. Also, certain of our operations are subject to EPA rules requiring the monitoring and annual reporting of GHG emissions from specified onshore and offshore production sources. In December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France and agreed to review its GHG emissions and set GHG emission reduction goals every five years beginning in 2020. Although this agreement does not create any binding obligations, it does include pledges to voluntarily limit or reduce future emissions. In August 2017, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Climate Agreement, which would result in an effective exit date of November 2020. Notwithstanding any withdrawal from this agreement, the implementation of substantial limitations on GHG emissions in areas where we conduct operations could adversely affect demand for oil and natural gas.

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 CFTC has finalized certain of its regulations under the Dodd-Frank Act, but others remain to be finalized or implemented. It is not possible at this time to predict when this will be accomplished or what the terms of the final rules will be, so the impact of those rules is uncertain at this time.
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. If we reduce the 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.

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

Pursuant to authority under federal law, 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 HCAs, 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 HCAs; (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 or replacements of pipeline segments 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 replacements of pipeline segments deemed necessary to ensure the safe and reliable operation of our pipelines. Moreover, the adoption of any new legislation or regulations that impose more stringent or costly pipeline integrity management standards could result in a material adverse effect on our results of operations or financial position.

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.

In June 2016, PHMSA’s statutory mandate regarding pipeline safety was extended through 2019, and PHMSA was given expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property, or the environment. The imposition of new safety requirements or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect thereto 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 could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position. For example, in January 2017, PHMSA issued a final rule that significantly extends and expands the reach of certain PHMSA integrity management requirements, such as, for example, periodic assessments, leak detection and repairs, regardless of the pipeline’s proximity to a high consequence area. The final rule also imposes new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. However, the date of implementation of this final rule by publication in the Federal Register remains uncertain given the January 2017 change in presidential administrations. Additionally, in March 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain natural gas lines and gathering lines including, among other things, expanding certain of PHMSA’s current regulatory safety programs for natural gas pipelines in newly defined “moderate consequence areas” that contain as few as five dwellings within a potential impact area; requiring natural gas pipelines installed before 1970 and thus excluded from certain pressure testing obligations to be tested to determine their MAOP; and requiring certain onshore and offshore gathering lines in Class I areas to comply with damage prevention, corrosion control, public education, MAOP limits, line markers and emergency planning standards. Additional requirements proposed by this proposed rulemaking would increase PHMSA’s integrity management requirements and also require consideration of seismicity in evaluating threats to pipelines. PHMSA has not yet finalized the March 2016 proposed rulemaking. Additionally, PHMSA and one or more state regulators, including the RRC, have in recent years expanded the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities, to assess compliance with hazardous liquids pipeline safety requirements. To the extent that PHMSA and/or state regulatory agencies are successful in asserting their jurisdiction in this manner, midstream operators of NGL fractionation facilities and associated storage facilities may be required to make operational changes or modifications at their facilities to meet standards beyond current OSHA and EPA 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.

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Some portions of our pipeline systems have been in service for several decades, and we have a limited ownership history with respect to certain of our assets. There could be unknown events or conditions or increased maintenance or repair expenses and downtime associated with our pipelines that could have a material adverse effect on our business and results of operations.

Some portions of the pipeline systems that we operate were in service for many decades prior to our purchase of them. Consequently, there may be historical occurrences or latent issues regarding our pipeline systems that our executive management may be unaware of and that may have a material adverse effect on our business and results of operations. The age and condition of our pipeline systems could also result in increased maintenance or repair expenditures, and any downtime associated with increased maintenance and repair activities could materially reduce our revenue. Any significant increase in maintenance and repair expenditures or loss of revenue due to the age or condition of our pipeline systems could adversely affect our business and results of operations.

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

Our operations are subject to stringent and comprehensive federal, tribal, state and local environmental laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These environmental laws and regulations may impose numerous obligations that are applicable to our operations, including: (i) the acquisition of permits to conduct regulated activities; (ii) restrictions on the types, quantities and concentrations of materials that can be released into the environment; (iii) limitations on the generation, management and disposal of wastes; (iv) limitations or prohibitions of construction and operating activities in environmentally sensitive areas such as wetlands, urban areas, wilderness regions and other protected areas; (v) requiring capital expenditures to limit or prevent releases of materials from our pipelines and facilities; and (vi) 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 remedial or corrective actions. Failure to comply with these laws, regulations and permits or any newly adopted legal requirements may result in the assessment of sanctions and administrative, civil and criminal penalties, the imposition of investigatory, remedial or corrective action obligations, the incurrence of capital expenditures, the occurrence of delays in the permitting, development or expansion of projects, and the issuance of injunctions limiting or preventing some or all of our operations in particular areas.
We may incur significant environmental costs and liabilities in connection with our operations due to our handling of natural gas, crude oil, NGLs and other petroleum products, because of air emissions and discharges related to our operations, and as a result of historical industry operations and waste disposal practices. For example, an accidental release as a result of our operations could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by owners of the properties through which our gathering or transportation systems pass, neighboring landowners, and other third parties for personal injury, natural resource and property damages, and fines or penalties for related violations of environmental laws or regulations. Joint and several strict liabilities may be incurred, without regard to fault, under certain of these environmental laws and regulations. In addition, stricter laws, regulations or enforcement policies could significantly increase our operational or compliance costs as well as the costs of any remedial actions that may become necessary, which could have a material adverse effect on our results of operations or financial condition. For example, regulatory initiatives targeting the reduction of certain air pollutants, such as ground level ozone or GHGs such as methane, have been proposed and/or adopted by the EPA but are currently subject to various legal impediments. The adoption of these or any other laws, regulations or other legally enforceable mandates could increase our oil and natural gas customers' operating and compliance costs as well as reduce the rate of production of oil or natural gas by operators with whom we have a business relationship, which could have a material adverse effect on our results of operations and cash flows.

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In addition, the legal requirements related to the disposal of wastewater to non-producing underground formations by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. One such concern relates to recent seismic events near injection wells used for the disposal of produced water resulting from oil and natural gas activities. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, Oklahoma has issued rules for wastewater disposal wells that impose certain permitting and operating restrictions and reporting requirements on disposal wells in proximity to faults and also, from time to time, is developing and implementing plans directing operators of wells injecting at certain depths where seismic incidents have occurred to restrict or suspend disposal well operations. The Texas Railroad Commission has adopted similar permitting, operating, and reporting rules for disposal wells. In addition, class action lawsuits to which we are not currently a party, have been pursued and additional litigation may arise in the future, in which plaintiffs have or may allege that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on our use of injection wells, which could have a material adverse effect on our capital expenditures and operating costs, financial condition, and results of operations.

Our construction of new assets may not result in revenue increases and is 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. In addition, 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 that we do not operate or control. As a result, among other things, we may be unable to control the amount of cash we 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 cash than 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 equity investments 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, the other owners of our equity investments 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 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 member.

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. Any loss of rights with respect to our real property, 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, crude oil, NGLs and produced water, 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 or losses of hydrocarbons or produced water as a result of the malfunction of equipment or facilities;

- fires and explosions (for example, see Items Affecting the Comparability of Our Financial Results, under Part II, Item 7 of this Form 10-K for a discussion of the incident at the DBM complex); and

- other hazards that could also result in personal injury, loss of life, pollution, natural resource damages and/or curtailment 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 that may occur in our business. 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, transportation and disposal 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. Further, to the extent any of our third-party customers is in financial distress or enters bankruptcy proceedings, the related customer contracts may be renegotiated at lower rates or rejected altogether.

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 has historically been 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 is subject to review and change by the Special Committee of our 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 81.6% 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 devote significant time to the business of Anadarko and are compensated by Anadarko accordingly. For example, all of the equity incentive compensation currently provided to the officers of our general partner is tied to Anadarko's common stock rather than our or WGP's common units.

- 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.

- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf.

- Our general partner has limited, and intends to continue to limit, its liability regarding our contractual and other obligations.

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

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

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

- Our general partner may elect to cause us to issue Class B units to it in connection with a resetting of the target distribution levels related to the IDRs without the approval of the Special Committee of the Board of Directors or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Read Part III, Item 13 of this Form 10-K for additional information.

A reduction in Anadarko's ownership interest in us may reduce its incentive to support the Partnership.

As discussed in Our Relationship with Anadarko Petroleum Corporation in Part I, Items 1 and 2 of this Form 10-K, 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. In 2014, Anadarko began monetizing a portion of its investment in WGP, including the sale of an aggregate of 20,550,000 WGP common units and 9,200,000 tangible equity units, which partially consist of prepaid equity purchase contracts that can be settled in WGP common units. To the extent Anadarko's net interest in us continues to decline through the sale of its WGP holdings or otherwise, Anadarko may be less incentivized to grow our business by offering us assets or commercial arrangements. For example, a decrease in Anadarko's net holdings in us could reduce its incentive to renew our commodity price swap agreements on terms as favorable as currently exist or at all. Accordingly, a decrease in Anadarko's net holdings in us could have a material adverse effect on our business, results of operations, financial position and ability to grow or make cash distributions to our unitholders.

The amount of cash we pay to our general partner under the IDRs increases as we grow our distributions to limited partners. This increased payout to our general partner raises our overall cost of capital which could impact distribution growth.

WGP, through its ownership of our general partner, holds all of our IDRs. While the IDRs provide Anadarko, which indirectly owns an 81.6% limited partner interest in WGP, financial incentive to continue to grow our business over time, 33.2% of our total distributions (excluding distributions paid on Class C units) were paid to our general partner as a result of its ownership of our IDRs during the fourth quarter of 2017. As this percentage grows over time, our cost of equity capital will increase, and we could become less competitive in pursuit of acquisition candidates. As a result, in the future we may be unable to acquire or construct assets on an accretive basis and further grow our limited partner distributions. We have from time to time discussed, and may discuss in the future, various transactions that would result in a simplification of our capital structure, including the potential modification or elimination of our IDRs. To date, no proposals have been made. Future evaluation of any such transaction, if any, will be based on a variety of factors, including general industry and market conditions. As a result, we can provide no assurance regarding the likelihood, timing or structure of any such transaction. If consummated, a simplification transaction could be dilutive to the holders of our common units and reduce the rate of our future distribution growth.

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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, more than half 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. Our general partner may, in good faith, significantly increase the amount of reimbursable general and administrative expenses in the future and any decision to do so would reduce the amount of cash otherwise available for distribution to our unitholders.

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

We have adopted certain requirements regarding those investors who may own our common 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.

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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 the 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, would 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;
- 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.

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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, 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 determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in subclauses (c) and (d) above, then it will be presumed that, in making its decision, the Board of Directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the Partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Our general partner may elect to cause us to issue Class B and general partner units to it in connection with a resetting of the target distribution levels related to its 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.

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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 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 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 (on an as-converted basis)) voting together as a single class is required to remove our general partner. As of February 12, 2018, WGP owned a 29.8% limited partner interest in us. Other subsidiaries of Anadarko separately owned an aggregate 9.1% 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, the purchasers of the Series A Preferred units (but only with respect to the common units such purchasers received upon conversion of the Series A Preferred units), and persons who acquired such units with the prior approval of the Board of Directors, cannot vote on any matter.

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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 all, but not less than all, of its general partner interest to a third party in connection with a merger or consolidation or the transfer of all or substantially all of its assets without the consent of our unitholders. On or after June 30, 2018, such transfer may be effected in whole or in part 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. Additionally, in March 2016, WGP entered into a secured credit facility under which it has pledged, among other things, its entire interest in our general partner. If WGP were to default, the lenders party to this facility could foreclose upon the interest and take control of our general partner. Any 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 12, 2018, WGP held 50,132,046 common units and other subsidiaries of Anadarko held 2,011,380 common units and 13,243,883 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 12, 2018, WGP owned a 29.8% limited partner interest in us, and other subsidiaries of Anadarko held an aggregate 9.1% 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 an 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, and possibly state, income taxes on our taxable income at the corporate tax rates, 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 to be 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 other 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.
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 21% for tax years beginning after December 31, 2017, 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.
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. At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income or franchise taxes, or other forms of taxation. For example, we are required to pay Texas margin tax on our gross income apportioned to Texas. Imposition of a similar tax on us in other jurisdictions to which we may expand our operations could substantially reduce the cash available for distribution to our unitholders.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes or 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. From time to time, members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. Although there is no current legislative proposal, a prior legislative proposal would have eliminated 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.
In addition, on January 24, 2017, final regulations regarding which activities give rise to qualifying income within the meaning of Section 7704 of the Code (the "Final Regulations") were published in the Federal Register. The Final Regulations are effective as of January 19, 2017, and apply to taxable years beginning on or after January 19, 2017. We do not believe the Final Regulations affect our ability to be treated as a partnership for U.S. federal income tax purposes.

However, any modification 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 similar or future legislative changes could negatively impact the value of an investment in our common units. You are urged to consult with your own tax advisor with respect to the status of regulatory and administrative developments and proposals and their potential effect on your investment in our common units.

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If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our common units, and the costs of any such contest would reduce 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 our treatment as a partnership for U.S. federal income tax purposes. 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, and a court may not agree with some or all of those positions. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. Moreover, the costs of any contest with the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced. In addition, our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us. To the extent possible under the new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each unitholder and former unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their respective interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

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 any U.S. 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. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, unitholders may be allocated taxable income and gain resulting from the sale, and our cash available for distribution would not increase. Similarly, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result in "cancellation of indebtedness income" being allocated to our unitholders as taxable income without any increase in our cash available for distribution. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

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

If a unitholder 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 their original cost. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if they sell their units, unitholders may incur a tax liability in excess of the amount of cash they receive from the sale.

A substantial portion of the amount realized from a unitholder's sale of units, whether or not representing gain, may be taxed as ordinary income to the unitholder due to potential recapture of items, including depreciation recapture. Thus, a unitholder may recognize both ordinary income and capital loss from the sale of units if the amount realized on the sale is less than the unitholder's adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which a unitholder sells units, the unitholder may recognize ordinary income from our allocations of income and gain prior to the sale and from recapture items, which generally cannot be offset by any capital loss recognized upon the sale of units.

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

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (or "IRAs") raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trades or businesses) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in us to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business ("effectively connected income"). Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a non-U.S. unitholder are subject to withholding at the highest applicable effective tax rate and a non-U.S. unitholder who sells or otherwise disposes of a unit is also subject to U.S. federal income tax on the gain realized from the sale or disposition of that unit.

The Tax Cuts and Jobs Act, enacted on December 22, 2017, and applicable to years beginning after December 31, 2017, imposes a withholding obligation of 10% of the amount realized upon a non-U.S. unitholder's sale or exchange of an interest in a partnership that is engaged in a U.S. trade or business. However, due to challenges of administering a withholding obligation applicable to open market trading and other complications, the IRS has temporarily suspended the application of this withholding rule to open market transfers of interests in publicly traded partnerships pending promulgation of regulations or other guidance that resolves the challenges. It is not clear if or when such regulations or other guidance will be issued. Non-U.S. unitholders should consult a 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 our common units.

Because we cannot match transferors and transferees of common units, we have adopted certain methods of allocating depreciation and amortization deductions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to the use of these methods 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 negatively impact the value of our common units or result in audit adjustments to unitholders' tax returns.

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. 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 (the "Allocation Date"), instead of on the basis of the date a particular common unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, 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 securities loan are urged to consult a tax advisor to determine whether it is advisable to 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 allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of our common units and could negatively impact 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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Our unitholders are subject to state and local taxes and return filing requirements in jurisdictions 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, 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

DBM, a wholly owned subsidiary of the Partnership, is currently in negotiations with the U.S. Environmental Protection Agency (the “EPA”) with respect to alleged noncompliance with certain Risk Management Plan regulations under the Clean Air Act at its DBM complex. In addition, Kerr-McGee Gathering LLC, also a wholly owned subsidiary of the Partnership, is currently in negotiations with the EPA and the Department of Justice with respect to alleged non-compliance with the leak detection and repair requirements of the federal Clean Air Act (“LDAR requirements”) at its Fort Lupton facility in the DJ Basin complex and WGR Operating, LP, another wholly owned subsidiary of the Partnership, is in negotiations with the EPA with respect to alleged non-compliance with LDAR requirements at its Granger, Wyoming facility. Although management cannot predict the outcome of settlement discussions in these matters, management believes that it is reasonably likely a resolution of these matters will result in a fine or penalty for each matter 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.

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 NYSE 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
2017				
High Price	$52.89	$57.15	$61.78	$67.44
Low Price	42.68	48.04	51.65	57.81
Distribution per common unit	0.920	0.905	0.890	0.875
2016				
High Price	$60.44	$55.24	$53.45	$48.50
Low Price	52.52	46.85	39.73	25.40
Distribution per common unit	0.860	0.845	0.830	0.815

As of February 12, 2018, there were 20 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 and outstanding 2,583,068 general partner units and 13,243,883 Class C units; there is no established public trading market for any such units. 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. During the quarter ended December 31, 2017, we issued 266,250 PIK Class C units with an implied fair value of $13.8 million to AMH, the holder of the Class C units. No proceeds were received as consideration for the issuance of the PIK Class C units. The PIK 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. All outstanding Class C units will convert into common units on a one-for-one basis on March 1, 2020, unless we elect to convert such units earlier or Anadarko extends the conversion date. For more information, see Note 3—Partnership Distributions and Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Securities authorized for issuance under equity compensation plans. The WES LTIP permits the issuance of up to 2,250,000 units, all of which remain available for future issuance as of December 31, 2017. Phantom unit grants under the WES 2008 LTIP have been made to each of the independent directors of our general partner and certain employees. Read the information under Part III, Item 12 of this Form 10-K, which is incorporated by reference into this Item 5.

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SELECTED INFORMATION FROM OUR PARTNERSHIP AGREEMENT

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

Available cash. Our 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. Working capital borrowings may only be those that, at the time of such borrowings, were intended to 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 into common units.

General partner interest and incentive distribution rights. As of December 31, 2017, our general partner was entitled to 1.5% of all quarterly distributions that we make prior to our liquidation and, as the holder of the IDRs, was entitled to incentive distributions at the maximum distribution sharing percentage of 48.0% for all periods presented, after the minimum quarterly distribution and the target distribution levels had been achieved. The maximum distribution sharing percentage of 49.5% 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

The following Summary Financial Information 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.
The term "Partnership assets" includes both the assets owned and the interests accounted for under the equity method by us as of December 31, 2017 (see Note 9—Equity Investments in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K). Because Anadarko controls us through its control of WGP, which owns the entire interest in our general partner, each acquisition 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 and Divestitures in the Notes to Consolidated Financial Statements under Part II, 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.

Acquisitions. The following table presents the acquisitions completed by us for the periods presented in the Summary Financial Information table below. Our consolidated financial statements include the combined financial results and operations for: (i) affiliate acquisitions for all periods presented and (ii) third-party acquisitions since the acquisition date.

	Acquisition Date	Percentage Acquired		Affiliate or Third-party Acquisition
Non-Operated Marcellus Interest (1)	03/01/2013	33.75	%	Anadarko
Marcellus Interest	03/08/2013	33.75	%	Third party
Mont Belvieu JV	06/05/2013	25	%	Third party
OTTCO	09/03/2013	100	%	Third party
TEFR Interests (2)	03/03/2014	Various (2)		Anadarko
DBM	11/25/2014	100	%	Third party
DBJV system	03/02/2015	50	%	Anadarko
Springfield system	03/14/2016	50.1	%	Anadarko
DBJV system (1)	03/17/2017	50	%	Third party

(1) See Property exchange below.
(2) Acquired a 20% interest in each of TEG and TEP and a 33.33% interest in FRP.

Property exchange. On March 17, 2017, we acquired the Additional DBJV System Interest from a third party in exchange for the Non-Operated Marcellus Interest and $155.0 million of cash consideration. We previously held a 50% interest in, and operated, the DBJV system.

Divestitures. In June 2017, the Helper and Clawson systems, located in Utah, were sold to a third party. In October 2016, the Hugoton system, located in Southwest Kansas and Oklahoma, was sold to a third party. In July 2015, the Dew and Pinnacle systems in East Texas were sold to a third party.

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The information in the following table should be read together with the Consolidated Financial Statements and the Notes to Consolidated Financial Statements, which are included under Part II, Item 8 of this Form 10-K, and with the information under the captions How We Evaluate Our Operations, Items Affecting the Comparability of Our Financial Results, Results of Operations, and Key Performance Metrics under Part II, Item 7 of this Form 10-K. See Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for a discussion of the expected impact the adoption of ASU 2014-09, Revenue from Contracts with Customers (Topic 606) will have on future revenues and expenses.

thousands except per-unit data, throughput, Adjusted gross margin per Mcf and Adjusted gross margin per Bbl	Summary Financial Information				
	2017	2016	2015	2014	2013
Statement of Operations Data (for the year ended):					
Total revenues and other	$2,248,356	$1,804,270	$1,752,072	$1,533,377	$1,200,060
Operating income (loss)	707,271	708,208	157,330	554,731	325,619
Net income (loss)	578,218	602,294	14,207	456,668	288,244
Net income attributable to noncontrolling interest	10,735	10,963	10,101	14,025	10,816
Net income (loss) attributable to Western Gas Partners, LP	567,483	591,331	4,106	442,643	277,428
Net income (loss) per common unit – basic	1.30	1.74	(1.95)	2.13	1.83
Net income (loss) per common unit – diluted	1.30	1.74	(1.95)	2.12	1.83
Distributions per unit	3.590	3.350	3.050	2.650	2.280
Balance Sheet Data (at year end):					
Total assets	$8,014,350	$7,733,028	$7,301,197	$7,549,785	$5,328,224
Total long-term liabilities	3,619,006	3,281,944	3,147,681	2,699,244	1,659,229
Total equity and partners' capital	3,971,011	4,135,779	3,918,028	4,568,462	3,422,675
Cash Flow Data (for the year ended):					
Net cash flows provided by (used in):					
Operating activities	$901,495	$917,585	$785,645	$694,495	$601,335
Investing activities	(763,604)	(1,105,534)	(500,277)	(2,740,175)	(1,858,912)
Financing activities	(417,002)	447,841	(254,389)	2,011,970	938,324
Capital expenditures	(673,638)	(473,858)	(637,503)	(804,822)	(851,771)
Throughput (MMcf/d except throughput measured in barrels):					
Total throughput for natural gas assets	3,680	4,064	4,300	3,984	3,611
Throughput attributable to noncontrolling interest for natural gas assets	105	124	142	165	168
Total throughput attributable to Western Gas Partners, LP for natural gas assets	3,575	3,940	4,158	3,819	3,443
Throughput for crude oil, NGL and produced water assets (MBbls/d)	201	184	186	154	62
Key Performance Metrics (for the year ended): [1]					
Adjusted gross margin for natural gas assets	$1,222,632	$1,194,877	$1,119,555	$993,397	$775,040
Adjusted gross margin for crude oil, NGL and produced water assets	153,846	142,566	131,492	103,102	31,664
Adjusted gross margin per Mcf for natural gas assets	0.94	0.83	0.74	0.71	0.62
Adjusted gross margin per Bbl for crude oil, NGL and produced water assets	2.10	2.11	1.93	1.84	1.40
Adjusted EBITDA	1,060,988	1,028,208	907,568	782,900	539,401
Distributable cash flow	928,967	852,446	781,383	661,133	455,238

(1) Adjusted gross margin, Adjusted EBITDA and Distributable cash flow are not defined in GAAP. For definitions and reconciliations of Adjusted gross margin, Adjusted EBITDA and Distributable cash flow to their most directly comparable financial measures calculated and presented in accordance with GAAP, see How We Evaluate Our Operations under Part II, 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

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 under Part II, Item 8 of this Form 10-K, and the information set forth in Risk Factors under Part I, Item 1A of this Form 10-K.

The term "Partnership assets" includes both the assets owned and the interests accounted for under the equity method by us as of December 31, 2017(see Note 9—Equity Investments in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K). Because Anadarko controls us through its control of WGP, which owns the entire interest in our general partner, each acquisition 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 and Divestitures in the Notes to Consolidated Financial Statements under Part II, 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.

EXECUTIVE SUMMARY

We are a growth-oriented Delaware MLP formed by Anadarko to acquire, own, develop and operate midstream assets. We currently own or have investments in assets located in the Rocky Mountains (Colorado, Utah and Wyoming), North-central Pennsylvania, Texas and New Mexico. We are engaged in the business of gathering, compressing, treating, processing and transporting natural gas; gathering, stabilizing and transporting condensate, NGLs and crude oil; and gathering and disposing of produced water. In addition, in our capacity as a processor of natural gas, we also buy and sell natural gas, NGLs or condensate under certain of our contracts. We provide these midstream services for Anadarko, as well as for third-party producers and customers. As of December 31, 2017, our assets and investments consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Gathering systems [1]	12	3	3	2
Treating facilities	19	3	—	3
Natural gas processing plants/trains	20	4	—	2
NGL pipelines	2	—	—	3
Natural gas pipelines	5	—	—	—
Oil pipelines	—	1	—	1

(1) Includes the DBM water systems.

Significant financial and operational events during the year ended December 31, 2017, included the following:

- In March 2017, we acquired the Additional DBJV System Interest from a third party in exchange for the Non-Operated Marcellus Interest and $155.0 million of cash consideration, resulting in a net gain of $125.7 million. See Acquisitions and Divestitures under Part I, Items 1 and 2 of this Form 10-K for additional information.

- In May 2017, we reached an agreement with Anadarko to settle the outstanding Deferred purchase price obligation - Anadarko, arising from our acquisition of DBJV, whereby we made a cash payment to Anadarko of $37.3 million during the second quarter of 2017.

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- On March 1, 2017, 50% of the outstanding Series A Preferred units converted into common units on a one-for-one basis, and on May 2, 2017, all remaining Series A Preferred units converted into common units on a one-for-one basis. See Equity Offerings under Part I, Items 1 and 2 of this Form 10-K for additional information.

- We commenced operation of the DBM water systems in the second quarter of 2017 and Train VI at the DBM complex (with capacity of 200 MMcf/d) in the fourth quarter of 2017.

- In June 2017, we closed on the sale of our Helper and Clawson systems, which resulted in a net gain on divestiture of $16.3 million. See Acquisitions and Divestitures under Part I, Items 1 and 2 of this Form 10-K for additional information.

- In February 2017, Anadarko elected to extend the conversion date of the Class C units from December 31, 2017, to March 1, 2020.

- We received $52.9 million in cash proceeds from insurers in final settlement of our claims related to the incident at the DBM complex, including $29.9 million for business interruption insurance claims and $23.0 million for property insurance claims. See Items Affecting the Comparability of Our Financial Results within this Item 7 for additional information.

- We raised our distribution to $0.920 per unit for the fourth quarter of 2017, representing a 2% increase over the distribution for the third quarter of 2017 and a 7% increase over the distribution for the fourth quarter of 2016.

- Throughput attributable to Western Gas Partners, LP for natural gas assets totaled 3,575 MMcf/d for the year ended December 31, 2017, representing a 9% decrease compared to the year ended December 31, 2016.

- Throughput for crude oil, NGL and produced water assets totaled 201 MBbls/d for the year ended December 31, 2017, representing a 9% increase compared to the year ended December 31, 2016.

- Operating income (loss) was $707.3 million for the year ended December 31, 2017, which was approximately the same as for the year ended December 31, 2016.

- Adjusted gross margin for natural gas assets (as defined under the caption How We Evaluate Our Operations within this Item 7) averaged $0.94 per Mcf for the year ended December 31, 2017, representing a 13% increase compared to the year ended December 31, 2016.

- Adjusted gross margin for crude oil, NGL and produced water assets (as defined under the caption How We Evaluate Our Operations within this Item 7) averaged $2.10 per Bbl for the year ended December 31, 2017, which was approximately the same as for the year ended December 31, 2016.

Anadarko’s Colorado Response. Following a home explosion in Firestone, Colorado in April 2017, Anadarko took precautionary measures to shut in all operated vertical wells in the DJ Basin to conduct additional inspections. It subsequently tested and permanently plugged, abandoned, and capped all one-inch return lines associated with these wells. In May 2017, the Colorado Oil & Gas Conservation Commission issued a two-phase Notice to Operators (“NTO”) requiring all operators to inventory and integrity test existing flowlines within 1,000 feet of a building unit and abandon all inactive flowlines in such areas. During the third quarter, Anadarko substantially completed the requirements of the NTO. In August 2017, following a three-month review of oil and gas operations, the Governor of Colorado announced several policy initiatives designed to enhance public safety, which are to be implemented over the next several months through rulemaking or legislation. Anadarko continues to work cooperatively with state regulators and others and is also cooperating with the NTSB in its investigation related to the incident.

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OUR OPERATIONS

Our results are driven primarily by the volumes of natural gas, NGLs, crude oil and produced water we service through our systems. In our operations, we contract with producers and customers to provide midstream services focused on natural gas, NGLs, crude oil and produced water. We gather natural gas from individual wells or production facilities located near our gathering systems and the natural gas may be compressed and delivered to a processing plant, treating facility or downstream pipeline, and ultimately to end users. We treat and process a significant portion of the natural gas that we gather so that it will satisfy required specifications for pipeline transportation. We gather crude oil from individual wells or production facilities located near our gathering systems, and in some cases, treat or stabilize the crude oil to satisfy required specifications for pipeline transportation. We also gather and dispose of produced water.

We currently have operations in Colorado, Utah, Wyoming, North-central Pennsylvania, Texas and New Mexico, with a substantial portion of our business concentrated in the Rocky Mountains. For example, for the year ended December 31, 2017, 28% of our throughput for natural gas assets (excluding equity investment throughput) and 40% of our Adjusted gross margin was attributable to our DJ Basin complex.

For the year ended December 31, 2017, 61% of our total revenues and 41% of our throughput (excluding equity investment throughput) were attributable to transactions with Anadarko. We also recognized capital contributions from Anadarko of $58.6 million related to the above-market component of our commodity price swap agreements with Anadarko (see Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K). Anadarko supports our operations by providing dedications and/or minimum volume commitments with respect to a substantial portion of our throughput.

For the year ended December 31, 2017, 94% of our Adjusted 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 and on the volume of NGLs, crude oil and produced water we gather, process, treat, transport or dispose. 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.

For the year ended December 31, 2017, 6% of our Adjusted gross margin was attributable to percent-of-proceeds and keep-whole contracts, pursuant to which we have commodity price exposure. See How We Evaluate Our Operations within this Item 7. A 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, with such agreements set to expire on December 31, 2018.

For the year ended December 31, 2017, 96% of our Adjusted gross margin was derived from either long-term, fee-based contracts or from percent-of-proceeds or keep-whole contracts that were hedged with commodity price swap agreements. See Risk Factors under Part I, Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

We also have indirect exposure to commodity price risk in that the relatively volatile commodity price environment has caused and may continue to cause current or potential customers to delay drilling or shut in production in certain areas, which would reduce the volumes of hydrocarbons available for our systems. We also bear a limited degree of commodity price risk through settlement of imbalances. Read Item 7A. Quantitative and Qualitative Disclosures About Market Risk under Part II of this Form 10-K.

As a result of our acquisitions from Anadarko and third parties, our results of operations, financial position and cash flows may vary significantly in future periods. See 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 systems, we must connect to additional wells or production facilities. 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, NGLs, crude oil or produced water volumes currently serviced by our competitors. During the year ended December 31, 2017, we added 347 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 and to the annual budget approved by our Board of Directors. Pursuant to the omnibus agreement, Anadarko and our 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 NYSE; and
- independent auditor fees, legal expenses, investor relations expenses, director fees, and registrar and transfer agent fees.

See further detail in Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, 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 and other, less cost of product and reimbursements for electricity-related expenses recorded as revenue, plus distributions from equity investments and excluding the noncontrolling interest owner's 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 the midstream 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, and (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. These expenses are subject to variability, although a majority of our exposure to commodity price risk inherent in our percent-of-proceeds and keep-whole contracts is mitigated through our commodity price swap agreements with Anadarko. For a discussion of commodity price swap agreements, see Risk Factors under Part I, Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, 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 for natural gas assets and Adjusted gross margin per Bbl for crude oil, NGL and produced water 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 (loss) attributable to Western Gas Partners, LP, plus distributions from equity investments, non-cash equity-based compensation expense, interest expense, income tax expense, depreciation and amortization, impairments, and other expense (including lower of cost or market inventory adjustments recorded in cost of product), less gain (loss) on divestiture and other, net, 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 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 and the net settlement amounts from the sale and/or purchase of natural gas, condensate and NGLs under our commodity price swap agreements to the extent such amounts are not recognized as Adjusted EBITDA, less net cash paid (or to be paid) for interest expense (including amortization of deferred debt issuance costs originally paid in cash, offset by non-cash capitalized interest), maintenance capital expenditures, Series A Preferred unit distributions 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. Furthermore, to the extent Distributable cash flow includes realized amounts recorded as capital contributions from Anadarko attributable to activity under our commodity price swap agreements, it is not a reflection of our ability to generate cash from operations.

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Reconciliation of non-GAAP measures. Adjusted gross margin, Adjusted EBITDA and Distributable cash flow are not defined in GAAP. The GAAP measure used by us that is most directly comparable to Adjusted gross margin is operating income (loss), while net income (loss) 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 (loss) 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 (loss), net income (loss) 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 (loss), net income (loss) attributable to Western Gas Partners, LP 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 (loss), net income (loss) attributable to Western Gas Partners, LP 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 GAAP financial measure of operating income (loss) to the non-GAAP financial measure of Adjusted gross margin, (b) a reconciliation of the GAAP financial measures of net income (loss) attributable to Western Gas Partners, LP and net cash provided by operating activities to the non-GAAP financial measure of Adjusted EBITDA and (c) a reconciliation of the GAAP financial measure of net income (loss) attributable to Western Gas Partners, LP to the non-GAAP financial measure of Distributable cash flow:

	Year Ended December 31,		
thousands	2017	2016	2015
Reconciliation of Operating income (loss) to Adjusted gross margin			
Operating income (loss)	$707,271	$708,208	$157,330
Add:			
Distributions from equity investments	110,465	103,423	98,298
Operation and maintenance	315,994	308,010	331,972
General and administrative	47,796	45,591	41,319
Property and other taxes	46,818	40,145	33,288
Depreciation and amortization	290,874	272,933	272,611
Impairments	178,374	15,535	515,458
Less:			
Gain (loss) on divestiture and other, net	132,388	(14,641)	57,024
Proceeds from business interruption insurance claims	29,882	16,270	—
Equity income, net – affiliates	85,194	78,717	71,251
Reimbursed electricity-related charges recorded as revenues	56,823	59,733	54,175
Adjusted gross margin attributable to noncontrolling interest	16,827	16,323	16,779
Adjusted gross margin	$1,376,478	$1,337,443	$1,251,047
Adjusted gross margin for natural gas assets	$1,222,632	$1,194,877	$1,119,555
Adjusted gross margin for crude oil, NGL and produced water assets	153,846	142,566	131,492

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thousands	Year Ended December 31, 2017	2016	2015
Reconciliation of Net income (loss) attributable to Western Gas Partners, LP to Adjusted EBITDA			
Net income (loss) attributable to Western Gas Partners, LP	$567,483	$591,331	$4,106
Add:			
Distributions from equity investments	110,465	103,423	98,298
Non-cash equity-based compensation expense	4,947	5,591	4,402
Interest expense	142,386	114,921	113,872
Income tax expense	4,905	8,372	45,532
Depreciation and amortization [(1)]	288,087	270,311	270,004
Impairments	178,374	15,535	515,458
Other expense [(1)]	145	224	1,290
Less:			
Gain (loss) on divestiture and other, net	132,388	(14,641)	57,024
Equity income, net – affiliates	85,194	78,717	71,251
Interest income – affiliates	16,900	16,900	16,900
Other income [(1)]	1,283	524	219
Income tax benefit	39	—	—
Adjusted EBITDA	$1,060,988	$1,028,208	$907,568
Reconciliation of Net cash provided by operating activities to Adjusted EBITDA			
Net cash provided by operating activities	$901,495	$917,585	$785,645
Interest (income) expense, net	125,486	98,021	96,972
Uncontributed cash-based compensation awards	25	856	214
Accretion and amortization of long-term obligations, net	(4,254)	3,789	(17,698)
Current income tax (benefit) expense	2,408	5,817	34,186
Other (income) expense, net	(1,299)	(479)	619
Distributions from equity investments in excess of cumulative earnings – affiliates	23,085	21,238	16,244
Changes in operating working capital:			
Accounts receivable, net	16,127	48,947	4,371
Accounts and imbalance payables and accrued liabilities, net	6,930	(58,359)	(1,006)
Other, net	4,491	4,367	720
Adjusted EBITDA attributable to noncontrolling interest	(13,506)	(13,574)	(12,699)
Adjusted EBITDA	$1,060,988	$1,028,208	$907,568
Cash flow information of Western Gas Partners, LP			
Net cash provided by operating activities	$901,495	$917,585	$785,645
Net cash used in investing activities	(763,604)	(1,105,534)	(500,277)
Net cash provided by (used in) financing activities	(417,002)	447,841	(254,389)

(1) Includes our 75% share of depreciation and amortization; other expense; and other income attributable to the Chipeta complex. Other expense also includes $0.1 million, $0.2 million and $0.4 million of lower of cost or market inventory adjustments, primarily at the DBM complex for the years ended December 31, 2017, 2016 and 2015, respectively.

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	Year Ended December 31,		
thousands except Coverage ratio	2017	2016	2015
Reconciliation of Net income (loss) attributable to Western Gas Partners, LP to Distributable cash flow and calculation of the Coverage ratio			
Net income (loss) attributable to Western Gas Partners, LP	$567,483	$591,331	$4,106
Add:			
Distributions from equity investments	110,465	103,423	98,298
Non-cash equity-based compensation expense	4,947	5,591	4,402
Non-cash settled interest expense, net [(1)]	71	(7,747)	14,400
Income tax (benefit) expense	4,866	8,372	45,532
Depreciation and amortization [(2)]	288,087	270,311	270,004
Impairments	178,374	15,535	515,458
Above-market component of swap agreements with Anadarko [(3)]	58,551	45,820	18,449
Other expense [(2)]	145	224	1,290
Less:			
Gain (loss) on divestiture and other, net	132,388	(14,641)	57,024
Equity income, net – affiliates	85,194	78,717	71,251
Cash paid for maintenance capital expenditures [(2)]	49,684	63,630	53,882
Capitalized interest	6,826	5,562	8,318
Cash paid for (reimbursement of) income taxes	1,194	838	(138)
Series A Preferred unit distributions	7,453	45,784	—
Other income [(2)]	1,283	524	219
Distributable cash flow	$928,967	$852,446	$781,383
Distributions declared [(4)]			
Limited partners – common units	$538,244		
General partner	286,624		
Total	$824,868		
Coverage ratio	1.13 x		

(1) Includes amounts related to the Deferred purchase price obligation - Anadarko. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

(2) Includes our 75% share of depreciation and amortization; other expense; cash paid for maintenance capital expenditures; and other income attributable to the Chipeta complex. Other expense also includes $0.1 million, $0.2 million and $0.4 million of lower of cost or market inventory adjustments, primarily at the DBM complex for the years ended December 31, 2017, 2016 and 2015, respectively.

(3) See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

(4) Reflects cash distributions of $3.590 per unit declared for the year ended December 31, 2017, including the cash distribution of $0.920 per unit paid on February 13, 2018, for the fourth-quarter 2017 distribution.

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ITEMS AFFECTING THE COMPARABILITY OF OUR FINANCIAL RESULTS

Our historical results of operations and cash flows for the periods presented may not be comparable to future or historic results of operations or cash flows for the reasons described below. Refer to Operating Results within this Item 7 for a discussion of our results of operations as compared to the prior periods. Further, see Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for a discussion of the expected impact the adoption of ASU 2014-09, Revenue from Contracts with Customers (Topic 606) will have on future revenues and expenses.

Gathering and processing agreements. Certain of the gathering agreements for the Haley, DBJV and Springfield systems allow for rate resets that target an agreed-upon rate of return over the life of the agreement. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Commodity price swap agreements. We have commodity price swap agreements with Anadarko to mitigate exposure to a majority of the commodity price risk inherent in our percent-of-proceeds and keep-whole contracts. On December 20, 2017, we renewed our commodity price swap agreements with Anadarko for the DJ Basin complex and the MGR assets through December 31, 2018, with an effective date of January 1, 2018. Revenues or costs attributable to volumes settled during the respective agreement period, at the applicable market price, are recognized in the consolidated statements of operations. We also record a capital contribution from Anadarko in our consolidated statements of equity and partners' capital for the amount by which the swap price exceeds the applicable market price. See Risk Factors under Part I, Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for further information.

Income taxes. Income we have earned on and subsequent to the date of the acquisition of the Partnership assets is subject only to Texas margin tax because we are a non-taxable entity for U.S. federal income tax purposes. With respect to assets acquired from Anadarko, we record Anadarko's historic current and deferred income taxes for the periods prior to our ownership of the assets. For periods subsequent to our acquisitions from Anadarko, we are not subject to tax except for the Texas margin tax and, accordingly, do not record current and deferred federal income taxes related to such assets.

Acquisitions and divestitures. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for additional information.

- DBJV acquisition. In March 2015, we acquired Anadarko's interest in DBJV for an anticipated cash payment of $282.8 million due to Anadarko on March 31, 2020. In May 2017, we reached an agreement with Anadarko to settle this obligation with a cash payment to Anadarko of $37.3 million, which was equal to the estimated net present value of the obligation at March 31, 2017.

- Dew and Pinnacle divestiture. In July 2015, the Dew and Pinnacle systems in East Texas were sold to a third party, resulting in a net gain on sale of $77.3 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations.

- Hugoton divestiture. In October 2016, the Hugoton system, located in Southwest Kansas and Oklahoma, was sold to a third party, resulting in a net loss on sale of $12.0 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations.

- Property exchange. On March 17, 2017, we acquired the Additional DBJV System Interest from a third party in exchange for the Non-Operated Marcellus Interest and $155.0 million of cash consideration. We previously held a

50% interest in, and operated, the DBJV system. The Property Exchange resulted in a net gain of $125.7 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations. Results of operations attributable to the Property Exchange were included in the consolidated statements of operations beginning on the acquisition date in the first quarter of 2017.

- Helper and Clawson divestiture. In June 2017, the Helper and Clawson systems, located in Utah, were sold to a third party, resulting in a net gain on sale of $16.3 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations.

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DBM complex. On December 3, 2015, there was an initial fire and secondary explosion at the processing facility within the DBM complex. The majority of the damage was to the liquid handling facilities and the amine treating units at the inlet of the complex. Train II sustained the most damage of the processing trains and returned to service in December 2016. Train III experienced minimal damage and returned to full service in May 2016. For the year ended December 31, 2015, $20.3 million of losses were recorded in Gain (loss) on divestiture and other, net in the consolidated statements of operations, related to this involuntary conversion event based on the difference between the net book value of the affected assets and the insurance claim receivable. During the year ended December 31, 2017, a $5.7 million loss was recorded in Gain (loss) on divestiture and other, net in the consolidated statements of operations, related to a change in the estimate of the amount that would be recovered under the property insurance claim based on further discussions with insurers. During the years ended December 31, 2017 and 2016, we received $52.9 million and $33.8 million, respectively, in cash proceeds from insurers related to the incident at the DBM complex, including $29.9 million and $16.3 million, respectively, in proceeds from business interruption insurance claims and $23.0 million and $17.5 million, respectively, in proceeds from property insurance claims. As of December 31, 2017 and 2016, the consolidated balance sheets included receivables of zero and $30.0 million, respectively, for the property insurance claim related to the incident at the DBM complex. For ease of reference throughout the remainder of this Management's Discussion and Analysis, the damage to the processing facility and resulting lack of processing capacity and associated financial statement impact are referred to as the "DBM outage." See Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Impairments. During 2015, we recognized impairments of $280.2 million at the Red Desert complex and $220.9 million at the Hilight system triggered by a reduction in estimated future cash flows caused by the low commodity price environment and resulting reduced producer drilling activity and related throughput. During 2017, we recognized an impairment of $158.8 million at the Granger complex due to a reduced throughput fee as a result of a producer's bankruptcy.

GENERAL TRENDS AND OUTLOOK

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

Impact of crude oil, natural gas and NGL prices. Crude oil, natural gas and NGL prices can fluctuate significantly, and have done so over time. These fluctuations in commodity prices affect the overall level of our customers' activity and how our customers allocate their capital within their own portfolio of assets. The relatively volatile commodity price environment over the past decade has impacted drilling activity in several of the basins served by our assets. Many of our customers, including Anadarko, have shifted capital spending towards opportunities with superior economics and reduced activity in other areas. To the extent possible, we will continue to connect new wells or production facilities to our systems to mitigate the impact of natural production declines in order to maintain throughput on our systems. However, our success in connecting additional wells or production facilities is dependent on the activity levels of our customers. Additionally, we will continue to evaluate the crude oil, NGL and natural gas price environments and adjust our capital spending plans to reflect our customers' anticipated activity levels, while maintaining appropriate liquidity and financial flexibility.

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Liquidity and access to capital markets. Under the terms of our partnership agreement, we are required to distribute all of our available cash to our unitholders, which makes us dependent upon raising capital to fund growth projects and acquisitions. Historically, we have accessed the debt and equity capital markets to raise money for growth projects and acquisitions. From time to time, capital market turbulence and investor sentiment towards MLPs have raised our cost of capital and, in some cases, temporarily made certain sources of capital unavailable. If we are unable either to access the capital markets or find alternative sources of capital at reasonable costs, our growth strategy will be more challenging to execute.

Changes in regulations. Our operations and the operations of our customers have been, and will continue to be, affected by political developments and federal, state, tribal, local and other laws and regulations that are becoming more numerous, more stringent and more complex. These laws and regulations include, among other things, limitations on hydraulic fracturing and other oil and gas operations, pipeline safety and integrity requirements, permitting requirements, environmental protection measures such as limitations on methane and other GHG emissions, and restrictions on produced water disposal wells. In addition, in certain areas in which we operate, public protests of oil and gas operations are becoming more frequent. Previously unsuccessful ballot initiatives that would impose setback requirements are being revived in Colorado, and we anticipate that regulation of the oil and gas industry will be an issue in that state's upcoming gubernatorial election. The number and scope of the regulations with which we and our customers must comply has a meaningful impact on our and their businesses, and new or revised regulations, reinterpretations of existing regulations, and permitting delays or denials could adversely affect both the throughput on and profitability of our assets.

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

Impact of interest rates. Overall, both short- and longer-term interest rates remained low during 2017 relative to historical averages. However, short-term interest rates experienced a sharp increase in response to the Federal Open Market Committee ("FOMC") raising its target range for the federal funds rate three separate times during 2017. These increases, and any future increases, in the federal funds rate will ultimately result in an increase in our financing costs. Additionally, as with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and an associated implied distribution yield. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity, or increase the cost of issuing equity, to make acquisitions, reduce debt or for other purposes. However, we expect our cost of capital to remain competitive, as our competitors would face similar circumstances.

Acquisition opportunities. A key component of our growth strategy is to acquire midstream assets from Anadarko and third parties over time. As of December 31, 2017, Anadarko's total domestic midstream asset portfolio, excluding the assets we own, consisted of three gathering systems, 2,902 miles of pipeline, 20 processing and/or treating facilities, three oil pipelines, one NGL pipeline and four produced water disposal systems.
We may also pursue certain asset acquisitions from third parties to the extent such acquisitions complement our or Anadarko's existing asset base or allow us to capture operational efficiencies from Anadarko's or third-party production. However, if we do not make additional acquisitions from Anadarko or third parties on economically acceptable terms, including as a result of increases in our overall cost of capital, our future growth could be limited, and the acquisitions we make could reduce, rather than increase, our cash flows generated from operations on a per-unit basis.

We have from time to time discussed, and may discuss in the future, various transactions that would result in a simplification of our capital structure, including the potential modification or elimination of our IDRs. To date, no proposals have been made. Future evaluation of any such transaction, if any, will be based on a variety of factors, including general industry and market conditions. As a result, we can provide no assurance regarding the likelihood, timing or structure of any such transaction. If consummated, a simplification transaction could be dilutive to the holders of our common units and reduce the rate of our future distribution growth.

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RESULTS OF OPERATIONS

OPERATING RESULTS

The following tables and discussion present a summary of our results of operations:

	Year Ended December 31,		
thousands	2017	2016	2015
Total revenues and other [(1)]	$2,248,356	$1,804,270	$1,752,072
Equity income, net – affiliates	85,194	78,717	71,251
Total operating expenses [(1)]	1,788,549	1,176,408	1,723,017
Gain (loss) on divestiture and other, net	132,388	(14,641)	57,024
Proceeds from business interruption insurance claims [(2)]	29,882	16,270	—
Operating income (loss)	707,271	708,208	157,330
Interest income – affiliates	16,900	16,900	16,900
Interest expense	(142,386)	(114,921)	(113,872)
Other income (expense), net	1,299	479	(619)
Income (loss) before income taxes	583,084	610,666	59,739
Income tax (benefit) expense	4,866	8,372	45,532
Net income (loss)	578,218	602,294	14,207
Net income attributable to noncontrolling interest	10,735	10,963	10,101
Net income (loss) attributable to Western Gas Partners, LP	$567,483	$591,331	$4,106
Key performance metrics [(3)]			
Adjusted gross margin	$1,376,478	$1,337,443	$1,251,047
Adjusted EBITDA	1,060,988	1,028,208	907,568
Distributable cash flow	928,967	852,446	781,383

(1) Revenues and other include amounts earned from services provided to our affiliates, as well as from the sale of residue and NGLs to our affiliates. Operating expenses include amounts charged by our affiliates for services as well as reimbursement of amounts paid by affiliates to third parties on our behalf. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

(2) See Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

(3) Adjusted gross margin, Adjusted EBITDA and Distributable cash flow are defined under the caption Key Performance Metrics within this Item 7. For reconciliations of these non-GAAP financial measures to their most directly comparable financial measures calculated and presented in accordance with GAAP, see How We Evaluate Our Operations–Reconciliation of non-GAAP measures within this Item 7.

For purposes of the following discussion, any increases or decreases “for the year ended December 31, 2017” refer to the comparison of the year ended December 31, 2017, to the year ended December 31, 2016, and any increases or decreases “for the year ended December 31, 2016” refer to the comparison of the year ended December 31, 2016, to the year ended December 31, 2015.

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Throughput

	Year Ended December 31,				
	2017	2016	Inc/ (Dec)	2015	Inc/ (Dec)
Throughput for natural gas assets (MMcf/d)					
Gathering, treating and transportation	958	1,537	(38)%	1,791	(14)%
Processing	2,563	2,350	9 %	2,331	1 %
Equity investment [1]	159	177	(10)%	178	(1)%
Total throughput for natural gas assets	3,680	4,064	(9)%	4,300	(5)%
Throughput attributable to noncontrolling interest for natural gas assets	105	124	(15)%	142	(13)%
Total throughput attributable to Western Gas Partners, LP for natural gas assets	3,575	3,940	(9)%	4,158	(5)%
Throughput for crude oil, NGL and produced water assets (MBbls/d)					
Gathering, treating, transportation and disposal	71	57	25 %	69	(17)%
Equity investment [2]	130	127	2 %	117	9 %
Total throughput for crude oil, NGL and produced water assets	201	184	9 %	186	(1)%

(1) Represents our 14.81% share of average Fort Union throughput and 22% share of average Rendezvous throughput.

(2) Represents our 10% share of average White Cliffs throughput, 25% share of average Mont Belvieu JV throughput, 20% share of average TEG and TEP throughput, and 33.33% share of average FRP throughput.

Natural gas assets

Gathering, treating and transportation throughput decreased by 579 MMcf/d for the year ended December 31, 2017, primarily due to the Property Exchange in March 2017 (decrease of 399 MMcf/d), production declines in the areas around the Marcellus Interest (decrease of 44 MMcf/d) and Springfield gas gathering systems (decrease of 44 MMcf/d), and the sale of the Hugoton system in October 2016 (decrease of 44 MMcf/d).

Gathering, treating and transportation throughput decreased by 254 MMcf/d for the year ended December 31, 2016, primarily due to decreased throughput at the Bison facility due to volumes being diverted to a third-party treater and the sale of the Dew and Pinnacle systems in July 2015.

Processing throughput increased by 213 MMcf/d for the year ended December 31, 2017, primarily due to the DBM outage in 2016, the start-up of Train IV and Train V at the DBM complex in May 2016 and October 2016, respectively, and increased production in the areas around the DJ Basin complex. These increases were partially offset by production declines in the areas around the Chipeta complex and MGR assets.

Processing throughput increased by 19 MMcf/d for the year ended December 31, 2016, primarily due to increased production in the areas around the DJ Basin complex and the start-up of Train IV at the DBM complex in May 2016. These increases were partially offset by production declines around the Chipeta and Granger complexes, the MGR assets, and the Hilight system.

Equity investment throughput decreased by 18 MMcf/d for the year ended December 31, 2017, primarily due to decreased throughput at the Rendezvous and Fort Union systems due to production declines in the area.

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Crude oil, NGL and produced water assets

Gathering, treating, transportation and disposal throughput increased by 14 MBbls/d for the year ended December 31, 2017, primarily due to throughput from the DBM water systems, which commenced operation during the second quarter of 2017, partially offset by decreased throughput at the Springfield oil gathering system due to production declines in the area. Equity investment throughput increased by 3 MBbls/d for the year ended December 31, 2017, primarily due to increased volumes on FRP and TEG as a result of increased NGL production and an increase at the Mont Belvieu JV due to higher inlet throughput. These increases were partially offset by decreased throughput at White Cliffs as a result of a competitive pipeline commencing service in September 2016.
Gathering, treating, transportation and disposal throughput decreased by 12 MBbls/d for the year ended December 31, 2016, primarily due to decreased throughput at the Springfield oil gathering system due to production declines in the area. Equity investment throughput increased by 10 MBbls/d for the year ended December 31, 2016, primarily due to an increase in volumes on FRP as a result of increased production in the DJ Basin area.

Gathering, Processing, Transportation and Disposal Revenues

	Year Ended December 31,				
thousands except percentages	2017	2016	Inc/ (Dec)	2015	Inc/ (Dec)
Gathering, processing, transportation and disposal revenues	$1,237,949	$1,227,849	1 %	$1,128,838	9 %

Revenues from gathering, processing, transportation and disposal increased by $10.1 million for the year ended December 31, 2017, primarily due to increases of (i) $88.7 million at the DBM complex due to increased throughput (see Operating Results–Throughput within this Item 7), (ii) $39.1 million at the DJ Basin complex due to a higher processing fee ($29.4 million) and increased throughput ($9.7 million) and (iii) $9.2 million at the DBM water systems, which commenced operation during the second quarter of 2017. These increases were partially offset by decreases of (i) $42.9 million due to the Property Exchange in March 2017, (ii) $31.7 million at the Springfield system and $14.0 million at the Chipeta complex due to throughput decreases, (iii) $16.0 million due to the sale of the Hugoton system in October 2016, (iv) $9.7 million at the Granger complex due to a lower processing fee and (v) $9.0 million at the Marcellus Interest systems due to decreased throughput.
Revenues from gathering, processing, transportation and disposal increased by $99.0 million for the year ended December 31, 2016, primarily due to increases of (i) $114.0 million at the DJ Basin complex resulting from increased throughput ($108.4 million) and a higher gathering fee ($5.6 million), as well as (ii) $19.8 million at the DBM complex due to increased throughput and a higher processing fee. These increases were partially offset by decreases of (i) $22.0 million at the Springfield system due to a decrease in throughput and (ii) $17.6 million due to the sale of the Dew and Pinnacle systems in July 2015.

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Natural Gas and Natural Gas Liquids Sales

	Year Ended December 31,				
thousands except percentages and per-unit amounts	2017	2016	Inc/ (Dec)	2015	Inc/ (Dec)
Natural gas sales [(1)]	$382,303	$230,366	66 %	$242,826	(5)%
Natural gas liquids sales [(1)]	607,630	341,947	78 %	375,123	(9)%
Total	$989,933	$572,313	73 %	$617,949	(7)%
Average price per unit [(1)]:					
Natural gas (per Mcf)	$2.92	$2.51	16 %	$3.28	(23)%
Natural gas liquids (per Bbl)	23.24	19.96	16 %	22.38	(11)%

(1) Excludes amounts considered above market with respect to our swap agreements for the MGR assets, DJ Basin complex and Hugoton system (until its divestiture in October 2016) that were recorded as capital contributions in the consolidated statements of equity and partners' capital. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

For the year ended December 31, 2017, average natural gas and NGL prices included the effects of commodity price swap agreements attributable to sales for the MGR assets and DJ Basin complex. For the years ended December 31, 2016 and 2015, average natural gas and NGL prices included the effects of commodity price swap agreements attributable to sales for the Hugoton system (until its divestiture in October 2016), MGR assets and DJ Basin complex. See Risk Factors under Part I, Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

The increase in natural gas sales of $151.9 million for the year ended December 31, 2017, was primarily due to increases of (i) $93.4 million at the DBM complex due to an increase in average price and volumes sold (see Operating Results–Throughput within this Item 7) and (ii) $64.2 million at the DJ Basin complex due to an increase in the swap market price and volumes sold. These increases were partially offset by a decrease of $12.3 million at the MGR assets due to the partial equity treatment of the above-market swap agreement beginning January 1, 2017.

The decrease in natural gas sales of $12.5 million for the year ended December 31, 2016, was primarily due to decreases of (i) $9.9 million at the Hilight system due to a decrease in average price and volumes sold, (ii) $5.5 million at the DJ Basin complex due to the partial equity treatment of the above-market swap agreement beginning July 1, 2015, partially offset by an increase in volumes sold and (iii) $3.8 million at the MGR assets due to a decrease in volumes sold. These decreases were partially offset by an increase of $8.7 million at the DBM complex due to an increase in volumes sold.

The increase in NGLs sales of $265.7 million for the year ended December 31, 2017, was primarily due to increases of (i) $255.3 million at the DBM complex due to an increase in average price and volumes sold (see Operating Results–Throughput within this Item 7), (ii) $46.3 million at the DJ Basin complex due to an increase in the swap market price and volumes sold and (iii) $15.3 million at the Hilight system due to an increase in average price. These increases were partially offset by a decrease of $64.5 million at the MGR assets due to the partial equity treatment of the above-market swap agreement beginning January 1, 2017.

The decrease in NGLs sales of $33.2 million for the year ended December 31, 2016, was primarily due to decreases of (i) $35.6 million at the MGR assets due to a decrease in volumes sold and (ii) $8.3 million and $4.8 million at the DJ Basin complex and Hugoton system, respectively, due to the partial equity treatment of the above-market swap agreements beginning July 1, 2015, for the DJ Basin complex and October 1, 2015, for the Hugoton system. These decreases were partially offset by an increase of $17.5 million at the DBM complex due to an increase in average price and volumes sold.

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Other Revenues

thousands except percentages	Year Ended December 31, 2017	2016	Inc/ (Dec)	2015	Inc/ (Dec)
Other revenues	$20,474	$4,108	NM	$5,285	(22)%

NM-Not Meaningful

For the year ended December 31, 2017, other revenues increased by $16.4 million, primarily due to deficiency fees of $8.8 million at the Chipeta complex and $7.2 million at the DBM water systems in 2017.

Equity Income, Net – Affiliates

thousands except percentages	Year Ended December 31, 2017	2016	Inc/ (Dec)	2015	Inc/ (Dec)
Equity income, net – affiliates	$85,194	$78,717	8 %	$71,251	10 %

For the year ended December 31, 2017, equity income, net – affiliates increased by $6.5 million, primarily due to an increase in equity income from the Mont Belvieu JV due to product price increases and due to our 14.81% share of an impairment loss determined by the managing partner of Fort Union in 2016.
For the year ended December 31, 2016, equity income, net – affiliates increased by $7.5 million, primarily due to our 14.81% share of an impairment loss determined by the managing partner of Fort Union in 2015, and increases in equity income from the TEFR Interests and the Mont Belvieu JV due to increased volumes.

Cost of Product and Operation and Maintenance Expenses

thousands except percentages	Year Ended December 31, 2017	2016	Inc/ (Dec)	2015	Inc/ (Dec)
NGL purchases (1)	$527,298	$238,660	121%	$251,222	(5)%
Residue purchases (1)	357,395	231,722	54 %	253,619	(9)%
Other	24,000	23,812	1 %	23,528	1 %
Cost of product	908,693	494,194	84 %	528,369	(6)%
Operation and maintenance	315,994	308,010	3 %	331,972	(7)%
Total cost of product and operation and maintenance expenses	$1,224,687	$802,204	53 %	$860,341	(7)%

(1) Excludes amounts considered above market with respect to our swap agreements for the MGR assets, DJ Basin complex and Hugoton system (until its divestiture in October 2016) that were recorded as capital contributions in the consolidated statements of equity and partners' capital. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

For the year ended December 31, 2017, cost of product expense included the effects of commodity price swap agreements attributable to purchases for the MGR assets and DJ Basin complex. For the years ended December 31, 2016 and 2015, cost of product expense included the effects of commodity price swap agreements attributable to purchases for the Hugoton system (until its divestiture in October 2016), MGR assets and DJ Basin complex. See Risk Factors under Part I, Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

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NGL purchases increased by $288.6 million for the year ended December 31, 2017, primarily due to increases of (i) $247.3 million at the DBM complex due to an increase in average price and volumes purchased (see Operating Results–Throughput within this Item 7), (ii) $52.8 million at the DJ Basin complex due to an increase in the swap market price and volumes purchased and (iii) $13.1 million at the Hilight system due to an increase in average price. These increases were partially offset by a decrease of $34.3 million at the MGR assets due to the partial equity treatment of the above-market swap agreement beginning January 1, 2017.

NGL purchases decreased by $12.6 million for the year ended December 31, 2016, primarily due to decreases of (i) $23.7 million at the MGR assets due to a decrease in volume and average swap price and (ii) $3.2 million at the Chipeta complex and $2.7 million at the Hilight system due to decreases in volumes and average prices. These decreases were partially offset by an increase of $19.0 million at the DBM complex due to an increase in volume.

Residue purchases increased by $125.7 million for the year ended December 31, 2017, primarily due to increases of (i) $81.5 million at the DBM complex due to an increase in average price and volumes purchased (see Operating Results–Throughput within this Item 7), (ii) $53.2 million at the DJ Basin complex due to an increase in the swap market price and volumes purchased and (iii) $4.8 million at the Hilight system due to an increase in average price. These increases were partially offset by a decrease of $15.8 million at the MGR assets due to the partial equity treatment of the above-market swap agreement beginning January 1, 2017.

Residue purchases decreased by $21.9 million for the year ended December 31, 2016, primarily due to decreases of (i) $9.8 million at the DJ Basin complex due to the partial equity treatment of the above-market swap agreement beginning July 1, 2015, partially offset by an increase in volume, (ii) $8.9 million at the Hilight system due to a decrease in volume and average price and (iii) $4.0 million at the MGR assets due to a decrease in volume, partially offset by an increase in average swap price. These decreases were partially offset by an increase of $3.4 million at the DBM complex due to an increase in volume.

Other items increased by $0.2 million for the year ended December 31, 2017, primarily due to changes in affiliate contract terms at the DJ Basin complex in 2017, partially offset by decreases at the DBM complex due to (i) fees paid in 2016 for rerouting volumes due to the DBM outage and (ii) changes in imbalance positions.

Other items increased by $0.3 million for the year ended December 31, 2016, primarily due to fees paid for rerouting volumes due to the DBM outage, partially offset by changes in imbalance positions, primarily at the DJ Basin and DBM complexes.

Operation and maintenance expense increased by $8.0 million for the year ended December 31, 2017, primarily due to increases of (i) $8.6 million at the DJ Basin complex primarily due to an increase in surface maintenance and plant repairs, (ii) $5.5 million at the DBM complex primarily due to increases in utilities expense and salaries and wages, partially offset by a decrease in surface maintenance and plant repairs, and (iii) $4.5 million due to the Property Exchange in March 2017. These increases were partially offset by decreases of (i) $7.5 million due to the sale of the Hugoton system in October 2016 and (ii) $4.4 million at the Chipeta complex primarily due to a decrease in utilities expense.

Operation and maintenance expense decreased by $24.0 million for the year ended December 31, 2016, primarily due to decreases of (i) $7.3 million at the Springfield system primarily due to decreases in salaries and wages and equipment rental, (ii) $4.6 million at the Chipeta complex primarily due to decreases in utilities expense and surface maintenance and plant repairs, (iii) $4.5 million due to the sale of the Dew and Pinnacle systems in July 2015, (iv) $4.4 million at the DJ Basin complex primarily due to decreases in surface maintenance and plant repairs, contract labor and consulting services, and other operating costs, partially offset by an increase in utilities expense, (v) $3.8 million at the Hugoton system primarily due to a decrease in salaries and wages, and (vi) $2.6 million at the Hilight system primarily due to a decrease in surface maintenance and plant repairs. These decreases were partially offset by an increase of $4.0 million at the DBM complex, primarily due to increases in surface maintenance and plant repairs, salaries and wages, and equipment rental, all partially offset by decreases in chemicals and treating services and other operating costs.

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Other Operating Expenses

	Year Ended December 31,				
thousands except percentages	2017	2016	Inc/ (Dec)	2015	Inc/ (Dec)
General and administrative	$47,796	$45,591	5 %	$41,319	10 %
Property and other taxes	46,818	40,145	17 %	33,288	21 %
Depreciation and amortization	290,874	272,933	7 %	272,611	— %
Impairments	178,374	15,535	NM	515,458	(97)%
Total other operating expenses	$563,862	$374,204	51 %	$862,676	(57)%

General and administrative expenses increased by $2.2 million for the year ended December 31, 2017, primarily due to (i) increases in personnel costs for which we reimbursed Anadarko pursuant to our omnibus agreement and (ii) bad debt expense. These increases were partially offset by decreases in legal and consulting fees.

General and administrative expenses increased by $4.3 million for the year ended December 31, 2016, primarily due to increases in personnel costs for which we reimbursed Anadarko pursuant to our omnibus agreement.

Property and other taxes increased by $6.7 million for the year ended December 31, 2017, primarily due to ad valorem tax increases of $4.2 million at the DJ Basin complex, $1.8 million at the DBJV system and $1.7 million at the DBM complex.

Property and other taxes increased by $6.9 million for the year ended December 31, 2016, primarily due to ad valorem tax increases of $7.2 million at the DJ Basin complex and $1.0 million at the DBM complex, partially offset by ad valorem tax decreases of $1.5 million at the Chipeta complex and $0.9 million due to the sale of the Hugoton system in October 2016.

Depreciation and amortization expense increased by $17.9 million for the year ended December 31, 2017, primarily due to depreciation expense increases of (i) $15.7 million due to the Property Exchange in March 2017, (ii) $11.3 million at the Bison facility due to a change in the estimated property life and (iii) $10.6 million related to capital projects at the DBM complex. These increases were partially offset by decreases of (i) $7.3 million at the Granger complex due to an impairment recorded in the first quarter of 2017 (see impairment expense below), (ii) $5.5 million due to the sale of the Hugoton system in October 2016, (iii) $4.4 million at the MGR assets due to a change in the estimated property life and (iv) $3.4 million at the DJ Basin complex due to a change in estimated salvage values.

Depreciation and amortization increased by $0.3 million for the year ended December 31, 2016, primarily due to depreciation expense increases of $22.9 million related to capital projects at the DJ Basin, DBM and Granger complexes and the DBJV, Non-Operated Marcellus Interest, and Springfield systems. These increases were partially offset by decreases of (i) $12.1 million at the MGR assets and the Hilight system due to asset impairments recognized in the first and fourth quarters of 2015, respectively, (ii) $7.0 million due to the sale of the Dew and Pinnacle systems in July 2015 and (iii) $3.5 million due to the sale of the Hugoton system in October 2016.

Impairment expense for the year ended December 31, 2017, included (i) a $158.8 million impairment at the Granger complex, (ii) an $8.2 million impairment at the Hilight system, (iii) a $3.7 million impairment at the Granger straddle plant, (iv) a $3.1 million impairment at the Fort Union system, (v) a $2.0 million impairment of an idle facility in northeast Wyoming and (vi) an impairment related to the cancellation of a pipeline project in West Texas.

Impairment expense for the year ended December 31, 2016, included (i) a $6.1 million impairment at the Newcastle system and (ii) $9.4 million of impairments primarily related to the cancellation of projects at the DJ Basin complex and the Springfield and DBJV systems, and the abandonment of compressors at the MIGC system.

Impairment expense for the year ended December 31, 2015, included (i) a $280.2 million impairment at the Red Desert complex, (ii) a $220.9 million impairment at the Hilight system and (iii) $14.4 million of impairments primarily related to the abandonment of compressors at the MIGC system and the cancellation of projects at the Non-Operated Marcellus Interest systems and the Brasada, Red Desert and DJ Basin complexes.

For further information on impairment expense for the years ended December 31, 2017, 2016 and 2015, see Note 7—Property, Plant and Equipment in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

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Interest Income – Affiliates and Interest Expense

	Year Ended December 31,				
thousands except percentages	2017	2016	Inc/ (Dec)	2015	Inc/ (Dec)
Note receivable – Anadarko	$16,900	$16,900	— %	$16,900	— %
Interest income – affiliates	$16,900	$16,900	— %	$16,900	— %
Third parties					
Long-term debt	$(142,525)	$(121,832)	17 %	$(102,058)	19 %
Amortization of debt issuance costs and commitment fees	(6,616)	(6,398)	3 %	(5,734)	12 %
Capitalized interest	6,826	5,562	23 %	8,318	(33)%
Affiliates					
Deferred purchase price obligation – Anadarko[1]	(71)	7,747	(101)%	(14,398)	(154)%
Interest expense	$(142,386)	$(114,921)	24 %	$(113,872)	1 %

(1) See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for a discussion of the Deferred purchase price obligation - Anadarko.

Interest expense increased by $27.5 million for the year ended December 31, 2017, primarily due to (i) accretion revisions in 2016 recorded as reductions to interest expense for the Deferred purchase price obligation - Anadarko (see Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K), (ii) $12.3 million of interest incurred on the 2026 Notes issued in July 2016 and (iii) $8.7 million of interest incurred on the additional 2044 Notes issued in October 2016. These increases were partially offset by an increase in capitalized interest of $1.3 million, primarily due to the construction of Train VI beginning in the fourth quarter of 2016 and the purchase of long-lead items associated with the Mentone plant, partially offset by a decrease due to the completion of Trains IV and V in May 2016 and October 2016, respectively, all located at the DBM complex.

Interest expense increased by $1.0 million for the year ended December 31, 2016, primarily due to (i) $10.9 million of interest incurred on the 2026 Notes issued in July 2016, (ii) $8.4 million of interest incurred on the 2025 Notes issued in June 2015 and (iii) $2.2 million of interest incurred on the additional 2044 Notes issued in October 2016. These increases were partially offset by accretion revisions recorded as reductions to interest expense for the Deferred purchase price obligation - Anadarko entered into in March 2015 (see Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K). Capitalized interest decreased by $2.8 million for the year ended December 31, 2016, primarily due to the completion of Lancaster Train II in June 2015 (within the DJ Basin complex), partially offset by an increase due to the construction of Trains IV, V and VI at the DBM complex. See Note 12—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

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Income Tax (Benefit) Expense

	Year Ended December 31,				
thousands except percentages	2017	2016	Inc/ (Dec)	2015	Inc/ (Dec)
Income (loss) before income taxes	$583,084	$610,666	(5)%	$59,739	NM
Income tax (benefit) expense	4,866	8,372	(42)%	45,532	(82)%
Effective tax rate	1 %	1 %		76 %	

We are not a taxable entity for U.S. federal income tax purposes. However, our income apportionable to Texas is subject to Texas margin tax. For the year ended December 31, 2017, the variance from the federal statutory rate, which is zero percent as a non-taxable entity, was primarily due to our share of Texas margin tax. For the years ended December 31, 2016 and 2015, the variance from the federal statutory rate was primarily due to federal and state taxes on pre-acquisition income attributable to Partnership assets acquired from Anadarko, and our share of Texas margin tax.

Texas House Bill 32, signed into law in June 2015, reduced the Texas margin tax rates by 0.25%. The law became effective January 1, 2016. We were required to include the impact of the law change on our deferred state income taxes in the period enacted. The adjustment, a reduction in deferred state income taxes in the amount of $2.2 million, was recorded in June 2015 and was included in the income tax (benefit) expense for the year ended December 31, 2015.

Income attributable to (i) the Springfield system prior to and including February 2016 and (ii) the DBJV system prior to and including February 2015, was subject to federal and state income tax. Income earned on the Springfield system and the DBJV system for periods subsequent to February 2016 and February 2015, respectively, was only subject to Texas margin tax on income apportionable to Texas.

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KEY PERFORMANCE METRICS

	Year Ended December 31,				
thousands except percentages and per-unit amounts	2017	2016	Inc/ (Dec)	2015	Inc/ (Dec)
Adjusted gross margin for natural gas assets [1]	$1,222,632	$1,194,877	2 %	$1,119,555	7 %
Adjusted gross margin for crude oil, NGL and produced water assets [2]	153,846	142,566	8 %	131,492	8 %
Adjusted gross margin [3]	1,376,478	1,337,443	3 %	1,251,047	7 %
Adjusted gross margin per Mcf for natural gas assets [4]	0.94	0.83	13 %	0.74	12 %
Adjusted gross margin per Bbl for crude oil, NGL and produced water assets [5]	2.10	2.11	— %	1.93	9 %
Adjusted EBITDA [3]	1,060,988	1,028,208	3 %	907,568	13 %
Distributable cash flow [3]	928,967	852,446	9 %	781,383	9 %

(1) Adjusted gross margin for natural gas assets is calculated as total revenues and other for natural gas assets, less reimbursements for electricity-related expenses recorded as revenue and cost of product for natural gas assets, plus distributions from our equity investments in Fort Union and Rendezvous, and excluding the noncontrolling interest owner's proportionate share of revenue and cost of product. See the reconciliation of Adjusted gross margin for natural gas assets to its most comparable GAAP measure under How We Evaluate Our Operations—Reconciliation of non-GAAP measures within this Item 7.

(2) Adjusted gross margin for crude oil, NGL and produced water assets is calculated as total revenues and other for crude oil, NGL and produced water assets, less reimbursements for electricity-related expenses recorded as revenue and cost of product for crude oil, NGL and produced water assets, plus distributions from our equity investments in White Cliffs, the Mont Belvieu JV, and the TEFR Interests. See the reconciliation of Adjusted gross margin for crude oil, NGL and produced water assets to its most comparable GAAP measure under How We Evaluate Our Operations—Reconciliation of non-GAAP measures within this Item 7.

(3) For a reconciliation of Adjusted gross margin, Adjusted EBITDA and Distributable cash flow to the most directly comparable financial measure calculated and presented in accordance with GAAP, see How We Evaluate Our Operations—Reconciliation of non-GAAP measures within this Item 7.

(4) Average for period. Calculated as Adjusted gross margin for natural gas assets, divided by total throughput (MMcf/d) attributable to Western Gas Partners, LP for natural gas assets.

(5) Average for period. Calculated as Adjusted gross margin for crude oil, NGL and produced water assets, divided by total throughput (MBbls/d) for crude oil, NGL and produced water assets.

Adjusted gross margin. Adjusted gross margin increased by $39.0 million for the year ended December 31, 2017, primarily due to (i) an increase in throughput at the DBM complex, (ii) an increase in processed volumes at the DJ Basin complex and (iii) the start-up of the DBM water systems during the second quarter of 2017. These increases were partially offset by decreases from (i) the Property Exchange in March 2017, (ii) lower throughput at the Springfield and Marcellus Interest systems, (iii) the partial equity treatment of the above-market swap agreement at the MGR assets beginning January 1, 2017, and (iv) the sale of the Hugoton system in October 2016.

Adjusted gross margin increased by $86.4 million for the year ended December 31, 2016, primarily due to an increase in volumes at the DJ Basin and DBM complexes and the Haley system. These increases were partially offset by the sale of the Dew and Pinnacle systems in July 2015 and lower volumes at the MGR assets and the Springfield and Hugoton systems.

Adjusted gross margin per Mcf for natural gas assets increased by $0.11 for the year ended December 31, 2017, primarily due to the Property Exchange in March 2017 and increased throughput at the DBM and DJ Basin complexes.

Adjusted gross margin per Mcf for natural gas assets increased by $0.09 for the year ended December 31, 2016, primarily due to increased volumes in the DJ Basin due to the start-up of Lancaster Train II in June 2015 (within the

DJ Basin complex) and increased volumes in West Texas due to the start-up of Trains IV and V (both within the DBM complex) in May 2016 and October 2016, respectively. These increases were partially offset by decreased volumes at the Springfield gas gathering system.

Adjusted gross margin per Bbl for crude oil, NGL and produced water assets decreased by $0.01 for the year ended December 31, 2017, primarily due to (i) lower throughput at the Springfield oil gathering system and (ii) the start-up of the DBM water systems during the second quarter of 2017. These decreases were partially offset by higher distributions received from TEP.

Adjusted gross margin per Bbl for crude oil, NGL and produced water assets increased by $0.18 for the year ended December 31, 2016, primarily due to higher distributions received from the Mont Belvieu JV and White Cliffs.

Adjusted EBITDA. Adjusted EBITDA increased by $32.8 million for the year ended December 31, 2017, primarily due to a $444.1 million increase in total revenues and other, a $13.6 million increase in business interruption proceeds and a $7.0 million increase in distributions from equity investments. These amounts were partially offset by a $414.5 million increase in cost of product (net of lower of cost or market inventory adjustments), an $8.0 million increase in operation and maintenance expenses, a $6.7 million increase in property and other tax expense, and a $2.8 million increase in general and administrative expenses excluding non-cash equity-based compensation expense.
Adjusted EBITDA increased by $120.6 million for the year ended December 31, 2016, primarily due to a $52.2 million increase in total revenues and other, a $33.9 million decrease in cost of product (net of lower of cost or market inventory adjustments), a $24.0 million decrease in operation and maintenance expenses, $16.3 million in business interruption proceeds, and a $5.1 million increase in distributions from equity investments. These amounts were partially offset by a $6.9 million increase in property and other tax expense, a $3.1 million increase in general and administrative expenses excluding non-cash equity-based compensation expense, and a $0.9 million increase in net income attributable to noncontrolling interest.

Distributable cash flow. Distributable cash flow increased by $76.5 million for the year ended December 31, 2017, primarily due to a $38.3 million decrease in Series A Preferred unit distributions, a $32.8 million increase in Adjusted EBITDA, a $13.9 million decrease in cash paid for maintenance capital expenditures, and a $12.7 million increase in the above-market component of the swap agreements with Anadarko. These amounts were partially offset by a $20.9 million increase in net cash paid for interest expense.
Distributable cash flow increased by $71.1 million for the year ended December 31, 2016, primarily due to a $120.6 million increase in Adjusted EBITDA and a $27.4 million increase in the above-market component of the swap agreements with Anadarko. These amounts were partially offset by distributions of $45.8 million on the Series A Preferred units issued in 2016, a $20.4 million increase in net cash paid for interest expense and a $9.7 million increase in cash paid for maintenance capital expenditures.

LIQUIDITY AND CAPITAL RESOURCES

Our primary cash requirements are for acquisitions and capital expenditures, debt service, customary operating expenses, quarterly distributions to our limited partners and general partner, and distributions to our noncontrolling interest owner. Our sources of liquidity as of December 31, 2017, included cash and cash equivalents, cash flows generated from operations, interest income on our $260.0 million note receivable from Anadarko, available borrowing capacity under the RCF, and issuances of additional equity or debt securities. We believe that cash flows generated from these sources will be sufficient to satisfy our short-term working capital requirements and long-term maintenance and expansion capital expenditure requirements. The amount of future distributions to unitholders will depend on our results of operations, financial condition, capital requirements and other factors, including the extension of our commodity price swap agreements, and will be determined by the Board of Directors on a quarterly basis. Due to our cash distribution policy, we expect to rely on external financing sources, including equity and debt issuances, to fund expansion capital expenditures and future acquisitions. However, to limit interest expense, we may use operating cash flows to fund expansion capital expenditures or acquisitions, which could result in subsequent borrowings under the RCF to pay distributions or fund other short-term working capital requirements.
During the second quarter of 2017, we reached a settlement with insurers related to the insurance claim filed for the incident at the DBM complex and final proceeds were received. Recoveries from the business interruption insurance claim related to the DBM outage were recognized as income when cash proceeds were received from insurers. During the year ended December 31, 2017, we received $52.9 million in cash proceeds from insurers, including $29.9 million for business interruption insurance claims and $23.0 million for property insurance claims (see Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K).

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Our partnership agreement requires that we distribute all of our available cash (as defined in the partnership agreement) to unitholders of record on the applicable record date within 45 days of the end of each quarter. We have made cash distributions to our unitholders each quarter since our IPO and have increased our quarterly distribution each quarter since the second quarter of 2009. The Board of Directors declared a cash distribution to our unitholders for the fourth quarter of 2017 of $0.920 per unit, or $216.6 million in aggregate, including incentive distributions, but excluding distributions on Class C units. The cash distribution was paid on February 13, 2018, to unitholders of record at the close of business on February 1, 2018. In connection with the closing of the DBM acquisition in November 2014, we issued Class C units that will receive distributions in the form of additional Class C units until March 1, 2020, unless earlier converted (see Note 3—Partnership Distributions in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K). The Class C unit distribution, if paid in cash, would have been $12.2 million for the fourth quarter of 2017.

Management continuously monitors our leverage position and coordinates our capital expenditure program, quarterly distributions and acquisition strategy with our expected cash flows and projected debt-repayment schedule. We will continue to evaluate funding alternatives, including additional borrowings and the issuance of debt or equity securities, to secure funds as needed or to refinance outstanding debt balances with longer term notes. To facilitate potential debt or equity securities offerings, we have the ability to sell securities under our shelf registration statements. Our ability to generate cash flows is subject to a number of factors, some of which are beyond our control. Read Risk Factors under Part I, Item 1A of this Form 10-K.

Working capital. As of December 31, 2017, we had a $170.3 million working capital deficit, which we define as the amount by which current liabilities exceed current assets. Working capital is an indication of our liquidity and potential need for short-term funding. Our working capital requirements are driven by changes in accounts receivable and accounts payable and factors such as credit extended to, and the timing of collections from, our customers, and the level and timing of our spending for maintenance and expansion activity. Our working capital deficit as of December 31, 2017, was primarily due to the costs incurred related to continued construction and expansion at the DBM and DJ Basin complexes and the DBJV system. As of December 31, 2017, we had $825.4 million available for borrowing under the RCF. See Note 12—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Capital expenditures. Our business is capital intensive, requiring significant investment to maintain and improve existing facilities or develop new midstream infrastructure. We categorize capital expenditures as either of the following:

- maintenance capital expenditures, which include those expenditures required to maintain the existing operating capacity and service capability of our assets, such as to replace system components and equipment that have been subject to significant use over time, become obsolete or reached the end of their useful lives, to remain in compliance with regulatory or legal requirements or to complete additional well connections to maintain existing system throughput and related cash flows; or

- expansion capital expenditures, which include expenditures to construct new midstream infrastructure and those expenditures incurred to extend the useful lives of our assets, reduce costs, increase revenues or increase system throughput or capacity from current levels, including well connections that increase existing system throughput.

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Capital expenditures in the consolidated statements of cash flows reflect capital expenditures on a cash basis, when payments are made. Capital incurred is presented on an accrual basis. Capital expenditures as presented in the consolidated statements of cash flows and capital incurred were as follows:

	Year Ended December 31,		
thousands	2017	2016	2015
Acquisitions	$159,208	$716,465	$14,417
Expansion capital expenditures	$623,674	$410,221	$583,282
Maintenance capital expenditures	49,964	63,637	54,221
Total capital expenditures (1) (2)	$673,638	$473,858	$637,503
Capital incurred (2)	$798,694	$491,349	$566,045

(1) Capital expenditures for the years ended December 31, 2017, 2016 and 2015, are presented net of $1.4 million, $6.1 million and $0.5 million, respectively, of contributions in aid of construction costs from affiliates.

(2) For the years ended December 31, 2017, 2016 and 2015, included $6.8 million, $5.6 million and $8.3 million, respectively, of capitalized interest.

Acquisitions during 2017 included the Additional DBJV System Interest and equipment purchases from Anadarko. Acquisitions during 2016 included Springfield and equipment purchases from Anadarko. Acquisitions during 2015 included equipment purchases from Anadarko and the post-closing purchase price adjustments related to the DBM acquisition. See Note 2—Acquisitions and Divestitures and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Capital expenditures, excluding acquisitions, increased by $199.8 million for the year ended December 31, 2017. Expansion capital expenditures increased by $213.5 million (including a $1.3 million increase in capitalized interest) for the year ended December 31, 2017, primarily due to (i) increases of $176.5 million at the DBJV system and $70.2 million at the DJ Basin complex, both due to pipe and compression projects, and (ii) an increase of $50.2 million due to the construction of the DBM water systems. These increases were partially offset by a decrease of $77.5 million at the DBM complex. Maintenance capital expenditures decreased by $13.7 million for the year ended December 31, 2017, primarily due to the Property Exchange in March 2017 and decreases at the DBM complex due to repairs made in 2016 as a result of the DBM outage. These decreases were partially offset by increases at the Hilight and Haley systems.

Capital expenditures, excluding acquisitions, decreased by $163.6 million for the year ended December 31, 2016. Expansion capital expenditures decreased by $173.1 million (including a $2.8 million decrease in capitalized interest) for the year ended December 31, 2016, primarily due to a decrease of $188.8 million at the DJ Basin complex as a result of decreased activity in 2016. In addition, there were decreases of $35.7 million at the Non-Operated Marcellus Interest systems, $30.0 million at the Springfield system, $18.4 million at the Hilight system, $13.5 million at the Haley system, and $9.3 million at the Marcellus Interest systems. These decreases were partially offset by an increase of $102.8 million due to continued construction at the DBM complex and an increase of $24.5 million at the DBJV system. Maintenance capital expenditures increased by $9.4 million, primarily due to an increase at the DBM complex, partially offset by decreased expenditures at the DJ Basin complex and the Non-Operated Marcellus Interest and Springfield systems.

For the year ending December 31, 2018, we estimate that our total capital expenditures, including our 75% share of Chipeta's capital expenditures and excluding acquisitions, will be between $1.0 billion to $1.1 billion and our maintenance capital expenditures will be between $80.0 million to $90.0 million.

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Historical cash flow. The following table and discussion present a summary of our net cash flows provided by (used in) operating activities, investing activities and financing activities:

	Year Ended December 31,		
thousands	2017	2016	2015
Net cash provided by (used in):			
Operating activities	$901,495	$917,585	$785,645
Investing activities	(763,604)	(1,105,534)	(500,277)
Financing activities	(417,002)	447,841	(254,389)
Net increase (decrease) in cash and cash equivalents	$(279,111)	$259,892	$30,979

Operating Activities. Net cash provided by operating activities decreased for the year ended December 31, 2017, and increased for the year ended December 31, 2016, primarily due to the impact of changes in working capital items. Refer to Operating Results within this Item 7 for a discussion of our results of operations as compared to the prior periods.

Investing Activities. Net cash used in investing activities for the year ended December 31, 2017, included the following:

- $673.6 million of capital expenditures, net of $1.4 million of contributions in aid of construction costs from affiliates, primarily related to construction and expansion at the DBJV system and the DBM and DJ Basin complexes and the construction of the DBM water systems;
- $155.3 million of cash consideration paid as part of the Property Exchange;
- $23.3 million of net proceeds from the sale of the Helper and Clawson systems in Utah;
- $23.1 million of distributions from equity investments in excess of cumulative earnings;
- $23.0 million of proceeds from property insurance claims attributable to the DBM outage; and
- $3.9 million of cash paid for equipment purchases from Anadarko.

Net cash used in investing activities for the year ended December 31, 2016, included the following:

- $712.5 million of cash paid for the acquisition of Springfield;
- $473.9 million of capital expenditures, net of $6.1 million of contributions in aid of construction costs from affiliates, primarily related to plant construction and expansion at the DBM and DJ Basin complexes and the DBJV system;
- $45.1 million of net proceeds from the sale of the Hugoton system in Southwest Kansas and Oklahoma;
- $21.2 million of distributions from equity investments in excess of cumulative earnings;
- $17.5 million of proceeds from property insurance claims attributable to the DBM outage; and
- $4.0 million of cash paid for equipment purchases from Anadarko.

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Net cash used in investing activities for the year ended December 31, 2015, included the following:

- $637.5 million of capital expenditures, net of $0.5 million of contributions in aid of construction costs from affiliates, primarily related to the construction of Train IV at the DBM complex, continued construction of Lancaster Train II (within the DJ Basin complex) and expansion at the DBJV system;
- $145.6 million of net proceeds from the sale of the Dew and Pinnacle systems in East Texas;
- $16.2 million of distributions from equity investments in excess of cumulative earnings;
- $11.4 million of cash contributed to equity investments, primarily related to expansion projects at White Cliffs, TEP and FRP;
- $10.9 million of cash paid for equipment purchases from Anadarko; and
- $3.5 million of cash paid for post-closing purchase price adjustments related to the DBM acquisition.

Financing Activities. Net cash used in financing activities for the year ended December 31, 2017, included the following:

- $801.3 million of distributions paid to our unitholders;
- $370.0 million of borrowings under the RCF, which were used for general partnership purposes, including funding of capital expenditures;
- $58.6 million of capital contributions from Anadarko related to the above-market component of swap agreements;
- $37.3 million of cash paid to Anadarko for the settlement of the Deferred purchase price obligation - Anadarko; and
- $13.6 million of distributions paid to the noncontrolling interest owner of Chipeta.

Net cash provided by financing activities for the year ended December 31, 2016, included the following:

- $900.0 million of repayments of outstanding borrowings under the RCF;
- $671.9 million of distributions paid to our unitholders;
- $599.3 million of borrowings under the RCF, net of extension costs, which were used to fund a portion of the Springfield acquisition and for general partnership purposes, including funding capital expenditures;
- $494.6 million of net proceeds from the 2026 Notes offering in July 2016, after underwriting and original issue discounts and offering costs, all of which was used to repay a portion of the outstanding borrowings under the RCF;
- $440.0 million of net proceeds from the issuance of 14,030,611 Series A Preferred units in March 2016, all of which was used to fund a portion of the acquisition of Springfield;
- $246.9 million of net proceeds from the issuance of 7,892,220 Series A Preferred units in April 2016, all of which was used to pay down amounts borrowed under the RCF in connection with the acquisition of Springfield;

- $203.3 million of net proceeds from the offering of the additional 2044 Notes in October 2016, after underwriting discounts and original issue premium and offering costs, all of which was used to repay amounts then outstanding under the RCF and for general partnership purposes, including capital expenditures;

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- $45.8 million of capital contributions from Anadarko related to the above-market component of swap agreements;
- $25.0 million of net proceeds from the sale of common units to WGP, all of which was used to fund a portion of the acquisition of Springfield;
- $23.5 million of net distributions paid to Anadarko representing pre-acquisition intercompany transactions attributable to Springfield; and
- $13.8 million of distributions paid to the noncontrolling interest owner of Chipeta.

Net cash used in financing activities for the year ended December 31, 2015, included the following:

- $610.0 million of repayments of outstanding borrowings under the RCF;
- $545.1 million of distributions paid to our unitholders;
- $489.6 million of net proceeds from the 2025 Notes offering in June 2015, after underwriting and original issue discounts and offering costs, all of which was used to repay a portion of the outstanding borrowings under the RCF;
- $400.0 million of borrowings under the RCF, which were used for general partnership purposes, including funding capital expenditures;
- $57.4 million of net proceeds from sales of common units under the registration statement filed with the SEC in August 2014 authorizing the issuance of up to an aggregate of $500.0 million of our common units. Net proceeds were used for general partnership purposes, including funding capital expenditures;
- $49.8 million of net distributions paid to Anadarko representing pre-acquisition intercompany transactions attributable to Springfield and DBJV;
- $18.4 million of capital contribution from Anadarko related to the above-market component of swap agreements; and
- $12.2 million of distributions paid to the noncontrolling interest owner of Chipeta.

Debt and credit facility. At December 31, 2017, our debt consisted of $500.0 million aggregate principal amount of the 2021 Notes, $670.0 million aggregate principal amount of the 2022 Notes, $350.0 million aggregate principal amount of the 2018 Notes, $600.0 million aggregate principal amount of the 2044 Notes, $500.0 million aggregate principal amount of the 2025 Notes, $500.0 million aggregate principal amount of the 2026 Notes and $370.0 million of borrowings outstanding under the RCF. As of December 31, 2017, the carrying value of our outstanding debt was $3.5 billion. See Note 12—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

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Senior Notes. The 2018 Notes, which are due in August 2018, were classified as long-term debt on the consolidated balance sheet at December 31, 2017, as we have the ability and intent to refinance these obligations using long-term debt.
In October 2016, we issued an additional $200.0 million in aggregate principal amount of 2044 Notes at a price to the public of 102.776% of the face amount plus accrued interest from October 1, 2016 to the settlement date. These notes were offered as additional notes under the indenture governing the 2044 Notes issued in March 2014 and are treated as a single class of securities with the 2044 Notes under such indenture. Including the effects of (i) the issuance premium for the October 2016 offering of the 2044 Notes, (ii) the issuance discount for the March 2014 offering of the 2044 Notes and (iii) the underwriting discounts, the effective interest rate of the 2044 Notes is 5.530%. Proceeds (net of underwriting discount of $1.8 million and debt issuance costs, and excluding accrued interest from October 1, 2016 to the settlement date) were used to repay amounts then outstanding under the RCF. The remaining proceeds were used for general partnership purposes, including capital expenditures.
The 2026 Notes issued in July 2016 were offered at a price to the public of 99.796% of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rate of the 2026 Notes is 4.787%. Proceeds (net of underwriting discount of $3.1 million, original issue discount and debt issuance costs) were used to repay a portion of the amount outstanding under the RCF.
At December 31, 2017, we were in compliance with all covenants under the indentures governing our outstanding notes.

Revolving credit facility. The $1.2 billion RCF bears interest at LIBOR, plus applicable margins ranging from 0.975% to 1.45%, or an alternate base rate equal to the greatest of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.5%, or (c) LIBOR plus 1%, in each case plus applicable margins currently ranging from zero to 0.45%, based upon our senior unsecured debt rating. In December 2016, the RCF was amended to extend the maturity date from February 2019 to February 2020. We are required to pay a quarterly facility fee currently ranging from 0.15% to 0.30% of the commitment amount (whether used or unused), based upon our senior unsecured debt rating. As of December 31, 2017, we had $370.0 million of outstanding RCF borrowings and $4.6 million in outstanding letters of credit, resulting in $825.4 million available for borrowing under the RCF. At December 31, 2017, the interest rate on the RCF was 2.87% and the facility fee rate was 0.20%.
The RCF contains certain covenants that limit, among other things, our ability, and that of certain of our subsidiaries, to incur additional indebtedness, grant certain liens, merge, consolidate or allow any material change in the character of our business, enter into certain affiliate transactions and use proceeds other than for partnership purposes. The RCF also contains various customary covenants, customary events of default and a maximum consolidated leverage ratio as of the end of each fiscal 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. At December 31, 2017, we were in compliance with all covenants under the RCF. In February 2018, the RCF was amended to extend the maturity date from February 2020 to February 2023 and expand borrowing capacity to $1.5 billion.
All notes and obligations under the RCF are recourse to our general partner. Our general partner is indemnified by wholly owned subsidiaries of Anadarko against any claims made against the general partner for our long-term debt and/or borrowings under the RCF.

Deferred purchase price obligation - Anadarko. Prior to our agreement with Anadarko to settle the deferred purchase price obligation early, the consideration that would have been paid for the March 2015 acquisition of DBJV from Anadarko consisted of a cash payment to Anadarko due on March 31, 2020. The cash payment would have been equal to (a) eight multiplied by the average of our share of Net Earnings (as defined below) of DBJV for the calendar years 2018 and 2019, less (b) our share of all capital expenditures incurred for DBJV between March 1, 2015, and February 29, 2020. Net Earnings was defined as all revenues less cost of product, operating expenses and property taxes, in each case attributable to DBJV on an accrual basis. In May 2017, we reached an agreement with Anadarko to settle this obligation with a cash payment to Anadarko of $37.3 million, which was equal to the estimated net present value of the obligation at March 31, 2017. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

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Securities. We may issue an indeterminate amount of common units and various debt securities under our effective shelf registration statement on file with the SEC. We may also issue common units under the $500.0 million COP, in amounts, at prices and on terms to be determined by market conditions and other factors at the time of offering. As of December 31, 2017, we had issued no common units under the registration statement associated with the $500.0 million COP.

Credit risk. We bear credit risk represented by our exposure to non-payment or non-performance by our counterparties, including Anadarko, financial institutions, customers and other parties. Generally, non-payment or non-performance results from a customer's inability to satisfy payables to us for services rendered or volumes owed pursuant to gas imbalance agreements. We examine and monitor the creditworthiness of third-party customers and may establish credit limits for third-party customers. A substantial portion of our throughput, however, comes from producers, including Anadarko, that have investment-grade ratings.
We do not, however, maintain a credit limit with respect to Anadarko. Consequently, we are subject to the risk of non-payment or late payment by Anadarko for gathering, processing, transportation and disposal fees and for proceeds from the sale of residue, NGLs and condensate to Anadarko.
We expect our exposure to concentrated risk of non-payment or non-performance to continue for as long as we remain substantially dependent on Anadarko for our revenues. Additionally, we are exposed to credit risk on the note receivable from Anadarko. We are also party to agreements with Anadarko under which Anadarko is required to indemnify us for certain environmental claims, losses arising from rights-of-way claims, failures to obtain required consents or governmental permits and income taxes with respect to the assets acquired from Anadarko. Finally, we have entered into various commodity price swap agreements with Anadarko in order to reduce our exposure to a majority of the commodity price risk inherent in our percent-of-proceeds and keep-whole contracts, and are subject to performance risk thereunder. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.
Our ability to make distributions to our unitholders may be adversely impacted if Anadarko becomes unable to perform under the terms of our gathering, processing, transportation and disposal agreements, our natural gas and NGL purchase agreements, Anadarko's note payable to us, our omnibus agreement, the services and secondment agreement, the contribution agreements or the commodity price swap agreements.

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CONTRACTUAL OBLIGATIONS

The following is a summary of our contractual cash obligations as of December 31, 2017. The table below excludes amounts classified as current liabilities on the consolidated balance sheets, other than the current portions of the categories listed within the table. It is expected that the majority of the excluded current liabilities will be paid in cash in 2018.

	Obligations by Period						
thousands	2018	2019	2020	2021	2022	Thereafter	Total
Long-term debt							
Principal	$350,000	$—	$370,000	$500,000	$670,000	$1,600,000	$3,490,000
Interest	145,793	140,141	131,115	112,727	102,327	832,319	1,464,422
Asset retirement obligations	2,304	—	2,554	—	—	140,840	145,698
Capital expenditures	212,463	—	—	—	—	—	212,463
Credit facility fees	2,400	2,400	375	—	—	—	5,175
Environmental obligations	833	323	323	141	141	57	1,818
Operating leases	8,402	7,506	1,615	460	467	2,021	20,471
Total	$722,195	$150,370	$505,982	$613,328	$772,935	$2,575,237	$5,340,047

Asset retirement obligations. When assets are acquired or constructed, the initial estimated asset retirement obligation is recognized in an amount equal to the net present value of the settlement obligation, with an associated increase in properties and equipment. Revisions in estimated asset retirement obligations may result from changes in estimated inflation rates, discount rates, asset retirement costs and the estimated timing of settlement. For additional information, see Note 11—Asset Retirement Obligations in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Capital expenditures. Included in this amount are capital obligations related to our expansion projects. We have other planned capital and investment projects that are discretionary in nature, with no substantial contractual obligations made in advance of the actual expenditures. See Note 13—Commitments and Contingencies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Credit facility fees. For additional information on credit facility fees required under the RCF, see Note 12—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Environmental obligations. We are subject to various environmental remediation obligations arising from federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters. We regularly monitor the remediation and reclamation process and the liabilities recorded and believe that the amounts reflected in our recorded environmental obligations are adequate to fund remedial actions to comply with present laws and regulations. For additional information on environmental obligations, see Note 13—Commitments and Contingencies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Operating leases. Anadarko, on our behalf, has entered into lease arrangements for corporate offices, shared field offices and equipment supporting our operations, for which it charges us rent. The amounts above represent existing contractual operating lease obligations that may be assigned or otherwise charged to us pursuant to the reimbursement provisions of the omnibus agreement. See Note 13—Commitments and Contingencies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

For additional information on contracts, obligations and arrangements we enter into from time to time, see Note 5—Transactions with Affiliates and Note 13—Commitments and Contingencies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

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CRITICAL ACCOUNTING ESTIMATES

The preparation of consolidated financial statements in accordance with GAAP requires our management to make informed judgments and estimates that affect the amounts of assets and liabilities as of the date of the financial statements and affect the amounts of revenues and expenses recognized during the periods reported. On an ongoing basis, management reviews its estimates, including those related to the determination of property, plant and equipment, asset retirement obligations, litigation, environmental liabilities, income taxes and fair values. Although these estimates are based on management’s best available knowledge of current and expected future events, changes in facts and circumstances or discovery of new information may result in revised estimates, and actual results may differ from these estimates. Management considers the following to be its most critical accounting estimates that involve judgment and discusses the selection and development of these estimates with the Audit Committee of our general partner. For additional information concerning our accounting policies, see Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Impairments of tangible assets. Property, plant and equipment are generally stated at the lower of historical cost less accumulated depreciation or fair value, if impaired. Because acquisitions of assets from Anadarko are transfers of net assets between entities under common control, the Partnership assets acquired by us from Anadarko are initially recorded at Anadarko’s historic carrying value. Assets acquired in a business combination or non-monetary exchange with a third party are initially recorded at fair value. Property, plant and equipment balances are evaluated for potential impairment when events or changes in circumstances indicate that their carrying amounts may not be recoverable from expected undiscounted cash flows from the use and eventual disposition of an asset. If the carrying amount of the asset is not expected to be recoverable from future undiscounted cash flows, an impairment may be recognized. Any impairment is measured as the excess of the carrying amount of the asset over its estimated fair value.
In assessing long-lived assets for impairments, our management evaluates changes in our business and economic conditions and their implications for recoverability of the assets’ carrying amounts. Since a significant portion of our revenues arises from gathering, processing and transporting production from Anadarko-operated properties, significant downward revisions in reserve estimates or changes in future development plans by Anadarko, to the extent they affect our operations, may necessitate assessment of the carrying amount of our affected assets for recoverability. Such assessment requires application of judgment regarding the use and ultimate disposition of the asset, long-range revenue and expense estimates, global and regional economic conditions, including commodity prices and drilling activity by our customers, as well as other factors affecting estimated future net cash flows. The measure of impairments to be recognized, if any, depends upon management’s estimate of the asset’s fair value, which may be determined based on the estimates of future net cash flows or values at which similar assets were transferred in the market in recent transactions, if such data is available. See Note 7—Property, Plant and Equipment in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for a description of impairments recorded during the years ended December 31, 2017, 2016 and 2015.

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Impairments of goodwill. 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, our goodwill represents the allocated portion of Anadarko's midstream goodwill attributed to the Partnership assets acquired from Anadarko. The carrying value of Anadarko's midstream goodwill represents the excess of the purchase price paid to a third-party entity over the estimated fair value of the identifiable assets acquired and liabilities assumed by Anadarko. Accordingly, our allocated goodwill balance does not represent, and in some cases is significantly different from, the difference between the consideration paid by us for acquisitions from Anadarko and the fair value of such net assets on their respective acquisition dates.

We evaluate whether goodwill has been impaired annually as of October 1, unless facts and circumstances make it necessary to test more frequently. Accounting standards require that goodwill be assessed for impairment at the reporting unit level. Management has determined that we have one operating segment and two reporting units: (i) gathering and processing and (ii) transportation. The carrying value of goodwill as of December 31, 2017, was $411.4 million for the gathering and processing reporting unit and $4.8 million for the transportation reporting unit. We allocated $1.6 million of goodwill to our divestiture of the Hugoton system upon its sale in October 2016 and $5.1 million of goodwill to our divestiture of the Dew and Pinnacle systems upon their sale in July 2015. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

We first assess whether an impairment of goodwill is necessary through a qualitative assessment to determine the likelihood of whether the fair value of the reporting unit is less than its carrying amount, including goodwill. If we conclude it is more likely than not that the fair value of the reporting unit exceeds the related carrying amount, then goodwill is not impaired and further testing is not necessary. If the qualitative assessment indicates the fair value of the reporting unit may be less than its carrying amount, we would compare the estimated fair value of the reporting unit to which goodwill is assigned to the carrying amount of the associated net assets, including goodwill, and determine whether an impairment is necessary.

When evaluating whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount, relevant events and circumstances are assessed, including the following:

- significant changes in our unit price;
- significant declines in commodity prices;
- significant increases in operating and capital costs;
- impairments recognized;
- acquisitions and disposals of assets;
- changes in throughput; and
- significant declines in trading multiples for our peers.

In this manner, estimating the fair value of our reporting units was not necessary based on the qualitative evaluation as of October 1, 2017. Qualitative factors were also assessed in the fourth quarter of 2017 to review any changes in circumstances subsequent to the annual test, including changes in commodity prices, and we concluded that estimating the fair value of our reporting units was not necessary at that time either. However, fair-value estimates of our reporting units may be required for goodwill impairment testing in the future, and if the carrying amount of a reporting unit, including goodwill, exceeds its fair value, goodwill is written down to the implied fair value through a charge to operating expense. See Note 1—Summary of Significant Accounting Policies and Note 8—Goodwill and Intangibles in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for more information.

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Because quoted market prices for our reporting units are not available, management must apply judgment in determining the estimated fair value of reporting units for purposes of performing the goodwill impairment test, when necessary. Management uses a variety of information to make these fair-value estimates, including market multiples of EBITDA. Specifically, our management estimates fair value by applying an estimated multiple to projected EBITDA. Management considers observable transactions in the market, as well as trading multiples for peers, to determine an appropriate multiple to apply against our projected EBITDA. A lower fair-value estimate in the future for any of our reporting units could result in a goodwill impairment. Factors that could trigger a lower fair-value estimate include sustained price declines, throughput declines, cost increases, regulatory or political environment changes, and other changes in market conditions such as decreased prices in market-based transactions for similar assets. Based on our most recent goodwill impairment test, we concluded, based on a qualitative assessment, that it is more likely than not that the fair value of each reporting unit exceeded the carrying value of the reporting unit. Therefore, no goodwill impairment was indicated, and no goodwill impairment has been recognized in our consolidated financial statements.

Impairments of intangible assets. Our intangible asset balance as of December 31, 2017 and 2016, primarily represents the fair value, net of amortization, of (i) contracts we assumed in connection with the Platte Valley acquisition in February 2011, which are being amortized on a straight-line basis over 50 years, (ii) interconnect agreements at Chipeta entered into in November 2012, which are being amortized on a straight-line basis over 10 years, and (iii) contracts we assumed in connection with the DBM acquisition in November 2014, which are being amortized on a straight-line basis over 30 years. See Note 8—Goodwill and Intangibles in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.
Management assesses intangible assets for impairment together with the related underlying long-lived assets whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Impairments exist when the carrying amount of an asset exceeds estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, estimates of future undiscounted cash flows take into account possible outcomes and probabilities of their occurrence. If the carrying amount of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, the impairment loss is measured as the excess of the asset's carrying amount over its estimated fair value, such that the asset's carrying amount is adjusted to its estimated fair value with an offsetting charge to impairment expense. No intangible asset impairment has been recognized in connection with these assets.

Fair value. Among other things, management estimates fair value (i) of long-lived assets for impairment testing, (ii) of reporting units for goodwill impairment testing when necessary, (iii) of assets and liabilities acquired in a business combination or exchanged in non-monetary transactions, and (iv) for the initial measurement of asset retirement obligations. When our management is required to measure fair value and there is not a market-observable price for the asset or liability or a similar asset or liability, management utilizes the cost, income, or market multiples valuation approach depending on the quality of information available to support management's assumptions. The cost approach is based on management's best estimate of the current asset replacement cost. The income approach uses management's best assumptions regarding expectations of projected cash flows, and discounts the expected cash flows using a commensurate risk adjusted discount rate. Such evaluations involve a significant amount of judgment, since the results are based on expected future events or conditions, such as sales prices, estimates of future throughput, capital and operating costs and the timing thereof, economic and regulatory climates and other factors. A multiples approach uses management's best assumptions regarding expectations of projected EBITDA and the multiple of that EBITDA that a buyer would pay to acquire an asset. Management's estimates of future net cash flows and EBITDA are inherently imprecise because they reflect management's expectation of future conditions that are often outside of management's control. However, assumptions used reflect a market participant's view of long-term prices, costs and other factors, and are consistent with assumptions used in our business plans and investment decisions. See Note 1-Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form

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OFF-BALANCE SHEET ARRANGEMENTS

We do not have any off-balance sheet arrangements other than operating leases and standby letters of credit. The information pertaining to operating leases and our standby letters of credit required for this item is provided under Note 13—Commitments and Contingencies and Note 12—Debt and Interest Expense, respectively, included in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

RECENT ACCOUNTING DEVELOPMENTS

See Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity price risk. Certain of our processing services are provided under percent-of-proceeds and keep-whole agreements in which Anadarko is typically responsible for the marketing of the natural gas, condensate and NGLs. Under percent-of-proceeds agreements, we receive a specified percentage of the net proceeds from the sale of residue and/or NGLs. Under keep-whole agreements, we keep 100% of the NGLs produced and the processed natural gas, or value of the natural gas, is returned to the producer, and since some of the gas is used and removed during processing, we compensate the producer for the amount of gas used and removed in processing by supplying additional gas or by paying an agreed-upon value for the gas used.

To mitigate a majority of our exposure to the commodity price risk inherent in our percent-of-proceeds and keep-whole contracts, we currently have in place commodity price swap agreements with Anadarko covering activity at the DJ Basin complex and the MGR assets. On December 20, 2017, we renewed these commodity price swap agreements through December 31, 2018, with an effective date of January 1, 2018. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

We consider our exposure to commodity price risk associated with the above-described arrangements to be minimal given the existence of the commodity price swap agreements with Anadarko and the relatively small amount of our operating income (loss) that is impacted by changes in market prices. Accordingly, we do not expect that a 10% increase or decrease in commodity prices would have a material impact on our operating income (loss), financial condition or cash flows for the next twelve months, excluding the effect of imbalances described below.

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

Interest rate risk. The FOMC raised its target range for the federal funds rate three separate times during 2017. These increases, and any future increases, in the federal funds rate will ultimately result in an increase in our financing costs. As of December 31, 2017, we had $370.0 million of outstanding borrowings under the RCF (which bears interest at a rate based on LIBOR or, at our option, an alternative base rate). A 10% change in LIBOR would have resulted in a nominal change in net income (loss) and the fair value of the borrowings under the RCF at December 31, 2017.

We may incur additional variable-rate debt in the future, either under the RCF or other financing sources, including commercial bank borrowings or debt issuances.

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Item 8. Financial Statements and Supplementary Data

WESTERN GAS PARTNERS, LP

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WESTERN GAS PARTNERS, LP

REPORT OF MANAGEMENT

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

MANAGEMENT'S ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting. The Partnership's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2017. This assessment was based on criteria established in the Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment using the COSO criteria, we concluded the Partnership's internal control over financial reporting was effective as of December 31, 2017.

KPMG LLP, the Partnership's independent registered public accounting firm, has issued an attestation report on the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2017.

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

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

February 16, 2018

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WESTERN GAS PARTNERS, LP

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on Internal Control Over Financial Reporting

We have audited Western Gas Partners, LP's (the Partnership) and subsidiaries' internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of Western Gas Partners, LP and subsidiaries as of December 31, 2017 and 2016, the related consolidated statements of operations, equity and partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes (collectively, the consolidated financial statements), and our report dated February 16, 2018 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

Western Gas Partners, LP's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ KPMG LLP
Houston, Texas
February 16, 2018

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WESTERN GAS PARTNERS, LP

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Western Gas Partners, LP (the Partnership) and subsidiaries as of December 31, 2017 and 2016, the related consolidated statements of operations, equity and partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 16, 2018 expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Partnership's auditor since 2007.
Houston, Texas
February 16, 2018

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WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
thousands except per-unit amounts	2017	2016	2015
Revenues and other – affiliates			
Gathering, processing, transportation and disposal	$656,795	$750,087	$772,361
Natural gas and natural gas liquids sales	692,447	478,145	447,106
Other	16,076	—	1,172
Total revenues and other – affiliates	1,365,318	1,228,232	1,220,639
Revenues and other – third parties			
Gathering, processing, transportation and disposal	581,154	477,762	356,477
Natural gas and natural gas liquids sales	297,486	94,168	170,843
Other	4,398	4,108	4,113
Total revenues and other – third parties	883,038	576,038	531,433
Total revenues and other	2,248,356	1,804,270	1,752,072
Equity income, net – affiliates	85,194	78,717	71,251
Operating expenses			
Cost of product [1]	908,693	494,194	528,369
Operation and maintenance [1]	315,994	308,010	331,972
General and administrative [1]	47,796	45,591	41,319
Property and other taxes	46,818	40,145	33,288
Depreciation and amortization	290,874	272,933	272,611
Impairments	178,374	15,535	515,458
Total operating expenses	1,788,549	1,176,408	1,723,017
Gain (loss) on divestiture and other, net [2]	132,388	(14,641)	57,024
Proceeds from business interruption insurance claims	29,882	16,270	—
Operating income (loss)	707,271	708,208	157,330
Interest income – affiliates	16,900	16,900	16,900
Interest expense [3]	(142,386)	(114,921)	(113,872)
Other income (expense), net	1,299	479	(619)
Income (loss) before income taxes	583,084	610,666	59,739
Income tax (benefit) expense	4,866	8,372	45,532
Net income (loss)	578,218	602,294	14,207
Net income attributable to noncontrolling interest	10,735	10,963	10,101
Net income (loss) attributable to Western Gas Partners, LP	$567,483	$591,331	$4,106
Limited partners' interest in net income (loss):			
Net income (loss) attributable to Western Gas Partners, LP	$567,483	$591,331	$4,106
Pre-acquisition net (income) loss allocated to Anadarko	—	(11,326)	(79,386)
Series A Preferred units interest in net (income) loss	(42,373)	(76,893)	—
General partner interest in net (income) loss [4]	(303,835)	(236,561)	(180,996)
Common and Class C limited partners' interest in net income (loss)[4]	221,275	266,551	(256,276)
Net income (loss) per common unit – basic and diluted[5]	$1.30	$1.74	$(1.95)

(1) Cost of product includes product purchases from Anadarko (as defined in Note 1) of $86.0 million, $80.5 million and $167.4 million for the years ended December 31, 2017, 2016 and 2015, respectively. Operation and maintenance includes charges from Anadarko of $72.5 million, $72.3 million and $77.1 million for the years ended December 31, 2017, 2016 and 2015, respectively. General and administrative includes charges from Anadarko of $39.1 million, $38.1 million and $33.9 million for the years ended December 31, 2017, 2016 and 2015,

respectively. See Note 5.

(2) Includes losses related to an incident at the DBM complex for the years ended December 31, 2017 and 2015. See Note 1.

(3) Includes affiliate (as defined in Note 1) amounts of $(0.1) million, $7.7 million and $(14.4) million for the years ended December 31, 2017, 2016 and 2015, respectively. See Note 2 and Note 12.

(4) Represents net income (loss) earned on and subsequent to the date of acquisition of the Partnership assets (as defined in Note 1). See Note 4.

(5) See Note 4 for the calculation of net income (loss) per common unit.

See accompanying Notes to Consolidated Financial Statements.

WESTERN GAS PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

	December 31,	
thousands except number of units	2017	2016
ASSETS		
Current assets		
Cash and cash equivalents	$78,814	$357,925
Accounts receivable, net [(1)]	160,432	223,223
Other current assets	14,816	12,866
Total current assets	254,062	594,014
Note receivable – Anadarko	260,000	260,000
Property, plant and equipment		
Cost	7,871,102	6,861,942
Less accumulated depreciation	2,140,211	1,812,010
Net property, plant and equipment	5,730,891	5,049,932
Goodwill	416,160	417,610
Other intangible assets	775,269	803,698
Equity investments	566,211	594,208
Other assets	11,757	13,566
Total assets	$8,014,350	$7,733,028
LIABILITIES, EQUITY AND PARTNERS' CAPITAL		
Current liabilities		
Accounts and imbalance payables [(2)]	$349,801	$247,076
Accrued ad valorem taxes	26,633	23,121
Accrued liabilities [(3)]	47,899	45,108
Total current liabilities	424,333	315,305
Long-term debt	3,464,712	3,091,461
Deferred income taxes	7,409	6,402
Asset retirement obligations and other	146,885	142,641
Deferred purchase price obligation – Anadarko [(4)]	—	41,440
Total long-term liabilities	3,619,006	3,281,944
Total liabilities	4,043,339	3,597,249
Equity and partners' capital		
Series A Preferred units (zero and 21,922,831 units issued and outstanding at December 31, 2017 and 2016, respectively) [(5)]	—	639,545
Common units (152,602,105 and 130,671,970 units issued and outstanding at December 31, 2017 and 2016, respectively)	2,950,010	2,536,872
Class C units (13,243,883 and 12,358,123 units issued and outstanding at December 31, 2017 and 2016, respectively) [(6)]	780,040	750,831
General partner units (2,583,068 units issued and outstanding at December 31, 2017 and 2016)	179,232	143,968
Total partners' capital	3,909,282	4,071,216
Noncontrolling interest	61,729	64,563
Total equity and partners' capital	3,971,011	4,135,779
Total liabilities, equity and partners' capital	$8,014,350	$7,733,028

(1) Accounts receivable, net includes amounts receivable from affiliates (as defined in Note 1) of $36.3 million and $76.6 million as of December 31, 2017 and 2016, respectively. Accounts receivable, net as of December 31, 2016, also includes an insurance claim receivable related to an incident at the DBM complex. See Note 1.

(2) Accounts and imbalance payables includes affiliate amounts of $0.3 million and zero as of December 31, 2017 and 2016, respectively.
(3) Accrued liabilities includes affiliate amounts of $0.2 million and zero as of December 31, 2017 and 2016, respectively.
(4) See Note 2.
(5) The Series A Preferred units converted into common units on a one-for-one basis in 2017. See Note 4.
(6) The Class C units will convert into common units on a one-for-one basis on March 1, 2020, unless the Partnership elects to convert such units earlier or Anadarko extends the conversion date. See Note 4.

See accompanying Notes to Consolidated Financial Statements.

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

	Partners' Capital						
thousands	Net Investment by Anadarko	Common Units	Class C Units	Series A Preferred Units	General Partner Units	Noncontrolling Interest	Total
Balance at December 31, 2014	$556,596	$3,119,714	$716,957	$—	$105,725	$ 69,470	$4,568,462
Net income (loss)	79,386	(238,166)	(18,110)	—	180,996	10,101	14,207
Above-market component of swap agreements with Anadarko (1)	—	18,449	—	—	—	—	18,449
Issuance of common units, net of offering expenses	—	57,353	—	—	—	—	57,353
Amortization of beneficial conversion feature of Class C units	—	(12,044)	12,044	—	—	—	—
Distributions to noncontrolling interest owner	—	—	—	—	—	(12,187)	(12,187)
Distributions to unitholders	—	(378,602)	—	—	(166,541)	—	(545,143)
Acquisitions from affiliates	(197,562)	23,286	—	—	—	—	(174,276)
Contributions of equity-based compensation from Anadarko	—	3,480	—	—	71	—	3,551
Net pre-acquisition contributions from (distributions to) Anadarko	(49,801)	—	—	—	—	—	(49,801)
Net contributions from (distributions to) Anadarko of other assets	—	(4,547)	—	—	(85)	—	(4,632)
Elimination of net deferred tax liabilities	41,844	—	—	—	—	—	41,844
Other	135	68	—	—	(2)	—	201
Balance at December 31, 2015	$430,598	$2,588,991	$710,891	$—	$120,164	$ 67,384	$3,918,028
Net income (loss)	11,326	269,018	28,642	45,784	236,561	10,963	602,294
Above-market component of swap agreements with Anadarko (1)	—	45,820	—	—	—	—	45,820
Issuance of common units, net of offering expenses	—	25,000	—	—	—	—	25,000
Issuance of Series A Preferred units, net of offering expenses	—	—	—	686,937	—	—	686,937
Beneficial conversion feature of Series A Preferred units	—	93,409	—	(93,409)	—	—	—
Amortization of beneficial conversion feature of Class C units and Series A Preferred	—	(42,407)	11,298	31,109	—	—	—

units							
Distributions to noncontrolling interest owner	—	—	—	—	—	(13,784)	(13,784)
Distributions to unitholders	—	(428,231)	—	(30,876)	(212,831)	—	(671,938)
Acquisitions from affiliates	(553,833)	(158,667)	—	—	—	—	(712,500)
Revision to Deferred purchase price obligation – Anadarko (2)	—	139,487	—	—	—	—	139,487
Contributions of equity-based compensation from Anadarko	—	4,131	—	—	83	—	4,214
Net pre-acquisition contributions from (distributions to) Anadarko	(23,491)	—	—	—	—	—	(23,491)
Net contributions from (distributions to) Anadarko of other assets	—	(572)	—	—	(9)	—	(581)
Elimination of net deferred tax liabilities	135,400	—	—	—	—	—	135,400
Other	—	893	—	—	—	—	893
Balance at December 31, 2016	$—	$2,536,872	$750,831	$639,545	$143,968	$ 64,563	$4,135,779
Net income (loss)	—	231,405	24,790	7,453	303,835	10,735	578,218
Above-market component of swap agreements with Anadarko (1)	—	58,551	—	—	—	—	58,551
Conversion of Series A Preferred units into common units (3)	—	686,936	—	(686,936)	—	—	—
Amortization of beneficial conversion feature of Class C units and Series A Preferred units	—	(66,718)	4,419	62,299	—	—	—
Distributions to noncontrolling interest owner	—	—	—	—	—	(13,569)	(13,569)
Distributions to unitholders	—	(510,228)	—	(22,361)	(268,711)	—	(801,300)
Acquisitions from affiliates	(1,263)	1,263	—	—	—	—	—
Revision to Deferred purchase price obligation – Anadarko (2)	—	4,165	—	—	—	—	4,165
Contributions of equity-based compensation from Anadarko	—	4,473	—	—	90	—	4,563
Net pre-acquisition contributions from (distributions to) Anadarko	1,263	—	—	—	—	—	1,263
Net contributions from (distributions to) Anadarko of other assets	—	3,139	—	—	50	—	3,189
Other	—	152	—	—	—	—	152
	$—	$2,950,010	$780,040	$—	$179,232	$ 61,729	$3,971,011

Balance at December 31,
2017

(1) See Note 5.
(2) See Note 2.
(3) See Note 4.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
thousands	2017	2016	2015
Cash flows from operating activities			
Net income (loss)	$578,218	$602,294	$14,207
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	290,874	272,933	272,611
Impairments	178,374	15,535	515,458
Non-cash equity-based compensation expense	4,922	4,735	4,188
Deferred income taxes	2,458	2,555	11,346
Accretion and amortization of long-term obligations, net	4,254	(3,789)	17,698
Equity income, net – affiliates	(85,194)	(78,717)	(71,251)
Distributions from equity investment earnings – affiliates	87,380	82,185	82,054
(Gain) loss on divestiture and other, net [1]	(132,388)	14,641	(57,024)
Lower of cost or market inventory adjustments	145	168	443
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable, net	(16,127)	(48,947)	(4,371)
Increase (decrease) in accounts and imbalance payables and accrued liabilities, net	(6,930)	58,359	1,006
Change in other items, net	(4,491)	(4,367)	(720)
Net cash provided by operating activities	901,495	917,585	785,645
Cash flows from investing activities			
Capital expenditures	(675,025)	(479,993)	(637,964)
Contributions in aid of construction costs from affiliates	1,387	6,135	461
Acquisitions from affiliates	(3,910)	(716,465)	(10,903)
Acquisitions from third parties	(155,298)	—	(3,514)
Investments in equity affiliates	(384)	(27)	(11,442)
Distributions from equity investments in excess of cumulative earnings – affiliates	23,085	21,238	16,244
Proceeds from the sale of assets to affiliates	—	623	925
Proceeds from the sale of assets to third parties	23,564	45,490	145,916
Proceeds from property insurance claims	22,977	17,465	—
Net cash used in investing activities	(763,604)	(1,105,534)	(500,277)
Cash flows from financing activities			
Borrowings, net of debt issuance costs	369,989	1,297,218	889,606
Repayments of debt	—	(900,000)	(610,000)
Settlement of the Deferred purchase price obligation – Anadarko [2]	(37,346)	—	—
Increase (decrease) in outstanding checks	5,593	2,079	(2,666)
Proceeds from the issuance of common units, net of offering expenses	(183)	25,000	57,353
Proceeds from the issuance of Series A Preferred units, net of offering expenses	—	686,937	—
Distributions to unitholders [3]	(801,300)	(671,938)	(545,143)
Distributions to noncontrolling interest owner	(13,569)	(13,784)	(12,187)
Net contributions from (distributions to) Anadarko	1,263	(23,491)	(49,801)
Above-market component of swap agreements with Anadarko [3]	58,551	45,820	18,449
Net cash provided by (used in) financing activities	(417,002)	447,841	(254,389)
Net increase (decrease) in cash and cash equivalents	(279,111)	259,892	30,979
Cash and cash equivalents at beginning of period	357,925	98,033	67,054
Cash and cash equivalents at end of period	$78,814	$357,925	$98,033
Supplemental disclosures			

Accretion expense and revisions to the Deferred purchase price obligation – Anadarko [2]	$(4,094)	$(147,234)	$174,276
Net distributions to (contributions from) Anadarko of other assets [4]	(3,189)	581	4,632
Interest paid, net of capitalized interest	137,326	106,485	94,720
Taxes paid (reimbursements received)	1,194	838	(138)
Accrued capital expenditures	204,309	79,253	61,454
Fair value of properties and equipment from non-cash third party transactions [2]	551,453	—	—

(1) Includes losses related to an incident at the DBM complex for the years ended December 31, 2017 and 2015. See Note 1.
(2) See Note 2.
(3) See Note 5.
(4) Includes $(1.4) million related to pipe and equipment purchases and $(1.8) million related to other assets for the year ended December 31, 2017. See Note 5.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General. Western Gas Partners, LP is a growth-oriented Delaware master limited partnership ("MLP") formed by Anadarko Petroleum Corporation in 2007 to acquire, own, develop and operate midstream assets.
For purposes of these consolidated financial statements, the "Partnership" refers to Western Gas Partners, LP and its subsidiaries. The Partnership's general partner, Western Gas Holdings, LLC (the "general partner"), is owned by Western Gas Equity Partners, LP ("WGP"), a Delaware MLP formed by Anadarko Petroleum Corporation in September 2012 to own the Partnership's general partner, as well as a significant limited partner interest in the Partnership. WGP has no independent operations or material assets other than owning the partnership interests in the Partnership (see Holdings of Partnership equity in Note 4). 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 the Partnership and the general partner, and "affiliates" refers to subsidiaries of Anadarko, excluding the Partnership, but including 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." "MGR assets" refers to the Red Desert complex and the Granger straddle plant.
The Partnership is engaged in the business of gathering, compressing, treating, processing and transporting natural gas; gathering, stabilizing and transporting condensate, natural gas liquids ("NGLs") and crude oil; and gathering and disposing of produced water. In addition, in its capacity as a processor of natural gas, the Partnership also buys and sells natural gas, NGLs or condensate under certain of its contracts. The Partnership provides these midstream services for Anadarko, as well as for third-party producers and customers. As of December 31, 2017, the Partnership's assets and investments consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Gathering systems [1]	12	3	3	2
Treating facilities	19	3	—	3
Natural gas processing plants/trains	20	4	—	2
NGL pipelines	2	—	—	3
Natural gas pipelines	5	—	—	—
Oil pipelines	—	1	—	1

[1] Includes the DBM water systems.

These assets and investments are located in the Rocky Mountains (Colorado, Utah and Wyoming), North-central Pennsylvania, Texas and New Mexico. The Partnership commenced operation of two produced water disposal systems in West Texas in the second quarter of 2017 and Train VI at the DBM complex in the fourth quarter of 2017.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Basis of presentation. The following table outlines the Partnership's ownership interests and the accounting method of consolidation used in the Partnership's consolidated financial statements:

	Percentage Interest	
Equity investments [(1)]		
Fort Union	14.81	%
White Cliffs	10	%
Rendezvous	22	%
Mont Belvieu JV	25	%
TEP	20	%
TEG	20	%
FRP	33.33	%
Proportionate consolidation [(2)]		
Marcellus Interest systems	33.75	%
Newcastle system	50	%
Springfield system	50.1	%
Full consolidation		
Chipeta [(3)]	75	%
DBJV system [(4)]	100	%

(1) Investments in non-controlled entities over which the Partnership exercises significant influence are accounted for under the equity method. "Equity investment throughput" refers to the Partnership's share of average throughput for these investments.

(2) The Partnership proportionately consolidates its associated share of the assets, liabilities, revenues and expenses attributable to these assets.

(3) The 25% interest in Chipeta Processing LLC ("Chipeta") held by a third-party member is reflected within noncontrolling interest in the consolidated financial statements.

(4) The Partnership acquired an additional 50% interest in the DBJV system (the "Additional DBJV System Interest") from a third party on March 17, 2017. See Note 2.

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States ("GAAP"). The consolidated financial statements include the accounts of the Partnership and entities in which it holds a controlling financial interest. All significant intercompany transactions have been eliminated.

Presentation of Partnership assets. The term "Partnership assets" includes both the assets owned and the interests accounted for under the equity method by the Partnership as of December 31, 2017 (see Note 9). Because Anadarko controls the Partnership through its control of WGP, which owns the Partnership's entire general partner interest, each acquisition of Partnership assets from Anadarko has been considered a transfer of net assets between entities under common control. As such, the Partnership assets acquired from Anadarko were initially recorded at Anadarko's historic carrying value, which did not correlate to the total acquisition price paid by the Partnership. Further, after an acquisition of Partnership assets from Anadarko, the Partnership may be required to recast its 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 the Partnership's acquisition of the Partnership assets from Anadarko are prepared from Anadarko's historical cost-basis accounts and

may not necessarily be indicative of the actual results of operations that would have occurred if the Partnership had owned the Partnership assets during the periods reported. Net income (loss) attributable to the Partnership assets acquired from Anadarko for periods prior to the Partnership's acquisition of the Partnership assets is not allocated to the limited partners.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Use of estimates. In preparing financial statements in accordance with GAAP, management makes informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Management evaluates its estimates and related assumptions regularly, using historical experience and other methods considered reasonable. Changes in facts and circumstances or additional information may result in revised estimates and actual results may differ from these estimates. Effects on the business, financial condition and results of operations resulting from revisions to estimates are recognized when the facts that give rise to the revisions become known. The information furnished herein reflects all normal recurring adjustments which are, in the opinion of management, necessary for a fair presentation of the consolidated financial statements, and certain prior-period amounts have been reclassified to conform to the current-year presentation.

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

Level 1 – Inputs represent unadjusted quoted prices in active markets for identical assets or liabilities.

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

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

In determining fair value, management uses observable market data when available, or models that incorporate observable market data. When a fair value measurement is required and there is not a market-observable price for the asset or liability or a market-observable price for a similar asset or liability, the cost, income, or multiples approach is used, depending on the quality of information available to support management's assumptions. The cost approach is based on management's best estimate of the current asset replacement cost. The income approach uses management's best assumptions regarding expectations of projected cash flows, and discounts the expected cash flows using a commensurate risk adjusted discount rate. Such evaluations involve a significant amount of judgment, since the results are based on expected future events or conditions, such as sales prices, estimates of future throughput, capital and operating costs and the timing thereof, economic and regulatory climates and other factors. A multiples approach uses management's best assumptions regarding expectations of projected earnings before interest, taxes, depreciation, and amortization ("EBITDA") and the multiple of that EBITDA that a buyer would pay to acquire an asset. Management's estimates of future net cash flows and EBITDA are inherently imprecise because they reflect management's expectation of future conditions that are often outside of management's control. However, the assumptions used reflect a market participant's view of long-term prices, costs and other factors, and are consistent with assumptions used in the Partnership's business plans and investment decisions.
In arriving at fair-value estimates, management uses relevant observable inputs available for the valuation technique employed. If a fair value measurement reflects inputs at multiple levels within the hierarchy, the fair value measurement is characterized based on the lowest level of input that is significant to the fair value measurement. Nonfinancial assets and liabilities initially measured at fair value include certain assets and liabilities acquired in a

third-party business combination, assets and liabilities exchanged in non-monetary transactions, goodwill and other intangibles, initial recognition of asset retirement obligations, and initial recognition of environmental obligations assumed in a third-party acquisition. Impairment analyses for long-lived assets, goodwill and other intangibles, and the initial recognition of asset retirement obligations and environmental obligations use Level 3 inputs.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

The fair value of debt reflects any premium or discount for the difference between the stated interest rate and the quarter-end market interest rate, and is based on quoted market prices for identical instruments, if available, or based on valuations of similar debt instruments. See Note 12.
The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable reported on the consolidated balance sheets approximate fair value due to the short-term nature of these items.

Cash equivalents. All highly liquid investments with a maturity of three months or less when purchased are considered to be cash equivalents.

Bad-debt reserve. Revenues are primarily from Anadarko, for which no credit limit is maintained. Exposure to bad debts is analyzed on a customer-by-customer basis for its third-party accounts receivable and the Partnership may establish credit limits for significant third-party customers. As of December 31, 2017 and 2016, bad-debt reserve was immaterial.

Imbalances. The consolidated balance sheets include imbalance receivables and payables resulting from differences in volumes received into the Partnership's systems and volumes delivered by the Partnership to customers. Volumes owed to or by the Partnership that are subject to monthly cash settlement are valued according to the terms of the contract as of the balance sheet dates and reflect market index prices. Other volumes owed to or by the Partnership are valued at the Partnership's weighted-average cost as of the balance sheet dates and are settled in-kind. As of December 31, 2017, imbalance receivables and payables were $1.6 million and $2.9 million, respectively. As of December 31, 2016, imbalance receivables and payables were $3.5 million and $3.0 million, respectively. Net changes in imbalance payables and receivables are reported in Cost of product in the consolidated statements of operations.

Inventory. The cost of NGLs inventories is determined by the weighted-average cost method on a location-by-location basis. Inventory is stated at the lower of weighted-average cost or market value and is reported in Other current assets on the consolidated balance sheets. See Note 10.

Property, plant and equipment. Property, plant and equipment are generally stated at the lower of historical cost less accumulated depreciation or fair value, if impaired. Because acquisitions of assets from Anadarko are transfers of net assets between entities under common control, the assets acquired from Anadarko are initially recorded at Anadarko's historic carrying value. The difference between the carrying value of net assets acquired from Anadarko and the consideration paid is recorded as an adjustment to partners' capital.
Assets acquired in a business combination or non-monetary exchange with a third party are initially recorded at fair value. All construction-related direct labor and material costs are capitalized. The cost of renewals and betterments that extend the useful life of property, plant and equipment is also capitalized. The cost of repairs, replacements and major maintenance projects that do not extend the useful life or increase the expected output of property, plant and equipment is expensed as incurred.
Depreciation is computed using the straight-line method based on estimated useful lives and salvage values of assets. However, subsequent events could cause a change in estimates, thereby impacting future depreciation amounts. Uncertainties that may impact these estimates include, but are not limited to, changes in laws and regulations relating to environmental matters, including air and water quality, restoration and abandonment requirements, economic conditions, and supply and demand in the area.
Management evaluates the ability to recover the carrying amount of its long-lived assets to determine whether its long-lived assets have been impaired. Impairments exist when the carrying amount of an asset exceeds estimates of

the undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, estimates of future undiscounted cash flows take into account possible outcomes and probabilities of their occurrence. If the carrying amount of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, the impairment loss is measured as the excess of the asset's carrying amount over its estimated fair value, such that the asset's carrying amount is adjusted to its estimated fair value with an offsetting charge to impairment expense. Refer to Note 7 for a description of impairments recorded during the years ended December 31, 2017, 2016 and 2015.

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Insurance recoveries. Involuntary conversions result from the loss of an asset because of some unforeseen event (e.g., destruction due to fire). Some of these events are insurable and result in property damage insurance recovery. Amounts that are received from insurance carriers are net of any deductibles related to the covered event. A receivable is recorded from insurance to the extent a loss is recognized from an involuntary conversion event and the likelihood of recovering such loss is deemed probable. To the extent that any insurance claim receivables are later judged not probable of recovery (e.g., due to new information), such amounts are expensed. A gain on involuntary conversion is recognized when the amount received from insurance exceeds the net book value of the retired asset(s). In addition, gains related to insurance recoveries are not recognized until all contingencies related to such proceeds have been resolved; that is, a cash payment is received from the insurance carrier or there is a binding settlement agreement with the carrier that clearly states that a payment will be made. To the extent that an asset is rebuilt, the associated expenditures are capitalized, as appropriate, on the consolidated balance sheets and presented as Capital expenditures in the consolidated statements of cash flows. With respect to business interruption insurance claims, income is recognized only when cash proceeds are received from insurers, which are presented in the consolidated statements of operations as a component of Operating income (loss).
On December 3, 2015, there was an initial fire and secondary explosion at the processing facility within the Delaware Basin Midstream, LLC (“DBM”) complex. The majority of the damage from the incident was to the liquid handling facilities and the amine treating units at the inlet of the complex. Train II sustained the most damage of the processing trains and returned to service in December 2016. Train III experienced minimal damage and returned to full service in May 2016. For the year ended December 31, 2015, $20.3 million of losses were recorded in Gain (loss) on divestiture and other, net in the consolidated statements of operations, related to this involuntary conversion event based on the difference between the net book value of the affected assets and the insurance claim receivable. During the year ended December 31, 2017, a $5.7 million loss was recorded in Gain (loss) on divestiture and other, net in the consolidated statements of operations, related to a change in the Partnership’s estimate of the amount that would be recovered under the property insurance claim based on further discussions with insurers. During the second quarter of 2017, the Partnership reached a settlement with insurers and final proceeds were received. During the years ended December 31, 2017 and 2016, the Partnership received $52.9 million and $33.8 million, respectively, in cash proceeds from insurers, including $29.9 million and $16.3 million, respectively, in proceeds from business interruption insurance claims and $23.0 million and $17.5 million, respectively, in proceeds from property insurance claims. As of December 31, 2017 and 2016, the consolidated balance sheets included receivables of zero and $30.0 million, respectively, for the property insurance claim related to the incident at the DBM complex.

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

Goodwill. 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, goodwill represents the allocated portion of Anadarko’s midstream goodwill attributed to the Partnership assets acquired from Anadarko. Refer to Note 8 for a discussion of goodwill. Goodwill is evaluated for impairment annually, as of October 1, or more often as facts and circumstances warrant. The Partnership has allocated goodwill on its two reporting units: (i) gathering and processing and (ii) transportation. An initial qualitative assessment is performed prior to proceeding to the comparison of the fair value of each reporting unit to which goodwill has been assigned, to the carrying amount of net assets, including goodwill, of each reporting unit. If management concludes, based on qualitative factors, that it is more likely than not that the fair value of the reporting unit exceeds its carrying amount, then goodwill is not impaired, and estimating the fair value of the reporting unit is not necessary. If the carrying amount of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value through a charge to operating expense. The carrying value of goodwill after such an impairment would represent a Level 3 fair value measurement.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Other intangible assets. The Partnership assesses intangible assets, as described in Note 8, for impairment together with related underlying long-lived assets whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. See Property, plant and equipment within this Note 1 for further discussion of management's process to evaluate potential impairment of long-lived assets.

Asset retirement obligations. A liability based on the estimated costs of retiring tangible long-lived assets is recognized as an asset retirement obligation in the period incurred. The liability is recognized at fair value, measured using discounted expected future cash outflows for the asset retirement obligation when the obligation originates, which generally is when an asset is acquired or constructed. The carrying amount of the associated asset is increased commensurate with the liability recognized. Over time, the discounted liability is adjusted to its expected settlement value through accretion expense, which is reported within Depreciation and amortization in the consolidated statements of operations. Subsequent to the initial recognition, the liability is also adjusted for any changes in the expected value of the retirement obligation (with a corresponding adjustment to property, plant and equipment) until the obligation is settled. Revisions in estimated asset retirement obligations may result from changes in estimated inflation rates, discount rates, asset retirement costs and the estimated timing of settling asset retirement obligations. See Note 11.

Environmental expenditures. The Partnership expenses environmental obligations related to conditions caused by past operations that do not generate current or future revenues. Environmental obligations related to operations that generate current or future revenues are expensed or capitalized, as appropriate. Liabilities are recorded when the necessity for environmental remediation or other potential environmental liabilities becomes probable and the costs can be reasonably estimated. Accruals for estimated losses from environmental remediation obligations are recognized no later than at the time of the completion of the remediation feasibility study. These accruals are adjusted as additional information becomes available or as circumstances change. Costs of future expenditures for environmental-remediation obligations are not discounted to their present value. See Note 13.

Segments. The Partnership's operations are organized into a single operating segment, the assets of which gather, compress, treat, process and transport natural gas; gather, stabilize and transport condensate, NGLs and crude oil; and gather and dispose of produced water in the United States.

Revenues and cost of product. The revenue recognition policies described in this section reflect the Partnership's revenue recognition through December 31, 2017. The Partnership adopted Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers (Topic 606) ("Topic 606"), effective January 1, 2018. See Accounting standards adopted in 2018 below for further discussion.
Under its fee-based gathering, treating, processing and disposal arrangements, the Partnership is paid a fixed fee based on the volume and/or thermal content of natural gas or produced water and recognizes revenues for its services in the month such services are performed. Producers' wells or production facilities are connected to the Partnership's gathering systems for delivery of natural gas to the Partnership's processing or treating plants, where the natural gas is processed to extract NGLs and condensate or treated in order to satisfy pipeline specifications. In some areas, where no processing is required, the producers' gas is gathered and delivered to pipelines for market delivery. Under cost-of-service gathering agreements, fees are earned for gathering and compression services based on rates calculated in a cost-of-service model and reviewed periodically over the life of the agreements. Under percent-of-proceeds contracts, revenue is recognized when the natural gas, NGLs or condensate is sold. The percentage of the product sale ultimately paid to the producer is recorded as a related cost of product expense.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

In certain circumstances, the Partnership purchases natural gas volumes at the wellhead or production facility for gathering and processing. As a result, the Partnership has volumes of NGLs and condensate to sell and volumes of residue to sell, to use for system fuel or to satisfy keep-whole obligations. In addition, depending upon specific contract terms, condensate and NGLs recovered during gathering and processing are either returned to the producer or retained and sold. Under keep-whole contracts, when condensate or NGLs are retained and sold, producers are kept whole for the condensate or NGL volumes through the receipt of a thermally equivalent volume of residue. The keep-whole contract conveys an economic benefit to the Partnership when the combined value of the individual NGLs is greater in the form of liquids than as a component of the natural gas stream; however, the Partnership is adversely impacted when the value of the NGLs is lower than the value of the natural gas stream including the liquids. The Partnership has commodity price swap agreements with Anadarko to mitigate exposure to a majority of the commodity price risk inherent in its percent-of-proceeds and keep-whole contracts. See Note 5. Revenue is recognized from the sale of condensate and NGLs upon transfer of title, and related purchases are recorded as cost of product.
The Partnership earns transportation revenues through firm contracts that obligate each of its customers to pay a monthly reservation or demand charge regardless of the pipeline capacity used by that customer. An additional commodity usage fee is charged to the customer based on the actual volume of natural gas transported. Transportation revenues are also generated from interruptible contracts pursuant to which a fee is charged to the customer based on volumes transported through the pipeline. Revenues for transportation of natural gas and NGLs are recognized over the period of firm transportation contracts or, in the case of usage fees and interruptible contracts, when the volumes are received into the pipeline. From time to time, certain revenues may be subject to refund pending the outcome of rate matters before the Federal Energy Regulatory Commission, and refund reserve liabilities are established where appropriate.
Revenues attributable to the fixed-fee component of gathering and processing contracts as well as demand charges and commodity usage fees on transportation contracts are reported as revenues from gathering, processing, transportation and disposal in the consolidated statements of operations. Proceeds from the sale of residue, NGLs and condensate are reported as revenues from natural gas and natural gas liquids sales in the consolidated statements of operations.

Equity-based compensation. Prior to October 17, 2017, phantom unit awards were granted under the Western Gas Partners, LP 2008 Long-Term Incentive Plan (the “WES 2008 LTIP”). On October 17, 2017, however, the Partnership’s common and Class C unitholders approved the Western Gas Partners, LP 2017 Long-Term Incentive Plan (the “WES 2017 LTIP”), which replaced the WES 2008 LTIP. As used in this section, the term “WES LTIP” refers to the WES 2008 LTIP with respect to awards granted prior to October 17, 2017, and to the WES 2017 LTIP with respect to awards granted after October 17, 2017. The WES 2017 LTIP permits the issuance of up to 2,250,000 units, all of which remain available for future issuance as of December 31, 2017. Upon vesting of each phantom unit awarded under the WES LTIP, the holder will receive common units of the Partnership or, at the discretion of the Board of Directors of its general partner (the “Board of Directors”), cash in an amount equal to the market value of common units of the Partnership on the vesting date. Equity-based compensation expense attributable to grants made under the WES LTIP impacts cash flows from operating activities only to the extent cash payments are made to a participant in lieu of issuance of common units to the participant. Stock-based compensation expense attributable to awards granted under the WES LTIP is amortized over the vesting periods applicable to the awards.
Additionally, general and administrative expenses include equity-based compensation costs allocated by Anadarko to the Partnership for grants made pursuant to (i) the Western Gas Equity Partners, LP 2012 Long-Term Incentive Plan (the “WGP LTIP”) and (ii) the Anadarko Petroleum Corporation 2008 and 2012 Omnibus Incentive Compensation Plans (Anadarko’s plans are referred to collectively as the “Anadarko Incentive Plans”) for all periods presented. Grants made under equity-based compensation plans result in equity-based compensation expense, which is determined by reference to the fair value of equity compensation. For equity-based awards ultimately settled through the issuance of

units or stock, the fair value is measured as of the date of the relevant equity grant. Equity-based compensation granted under the WGP LTIP and the Anadarko Incentive Plans does not impact cash flows from operating activities since the offset to compensation expense is recorded as a contribution to partners' capital in the consolidated financial statements at the time of contribution, when the expense is realized.

WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Income taxes. The Partnership generally is not subject to federal income tax or state income tax other than Texas margin tax on the portion of its income that is apportionable to Texas. Deferred state income taxes are recorded on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. The Partnership routinely assesses the realizability of its deferred tax assets. If the Partnership concludes that it is more likely than not that some of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. Federal and state current and deferred income tax expense was recorded on the Partnership assets prior to the Partnership's acquisition of these assets from Anadarko.
For periods beginning on and subsequent to the Partnership's acquisition of the Partnership assets, the Partnership makes payments to Anadarko pursuant to the tax sharing agreement entered into between Anadarko and the Partnership for its estimated share of taxes from all forms of taxation, excluding taxes imposed by the United States, that are included in any combined or consolidated returns filed by Anadarko. The aggregate difference in the basis of the Partnership's assets for financial and tax reporting purposes cannot be readily determined as the Partnership does not have access to information about each partner's tax attributes in the Partnership.
The accounting standards for uncertain tax positions defines the criteria an individual tax position must satisfy for any part of the benefit of that position to be recognized in the financial statements. The Partnership had no material uncertain tax positions at December 31, 2017 or 2016.
With respect to assets acquired from Anadarko, the Partnership recorded Anadarko's historic deferred income taxes for the periods prior to the Partnership's ownership of the assets. For periods subsequent to the Partnership's acquisition, the Partnership is not subject to tax except for the Texas margin tax and, accordingly, does not record deferred federal income taxes related to the assets acquired from Anadarko.

Net income (loss) per common unit. The Partnership applies the two-class method in determining net income (loss) per unit applicable to MLPs having multiple classes of securities including common units, Class C units, general partner units and incentive distribution rights ("IDRs"). The two-class method is an earnings allocation formula that treats participating securities as having rights to earnings that otherwise would have been available to common unitholders. Under the two-class method, net income (loss) per unit is calculated as if all of the earnings for the period were distributed pursuant to the terms of the relevant contractual arrangement. The accounting guidance provides the methodology for the allocation of undistributed earnings to the general partner, limited partners and IDR holders and the circumstances in which such an allocation should be made. For the Partnership, earnings per unit is calculated based on the assumption that the Partnership distributes to its unitholders an amount of cash equal to the net income of the Partnership, notwithstanding the general partner's ultimate discretion over the amount of cash to be distributed for the period, the existence of other legal or contractual limitations that would prevent distributions of all of the net income for the period or any other economic or practical limitation on the ability to make a full distribution of all of the net income for the period. See Note 4.

Accounting standards adopted in 2017. ASU 2017-04, Intangibles—Goodwill and Other (Topic 350) eliminates Step 2 from the goodwill impairment test in an effort to simplify the subsequent measurement of goodwill. The Partnership adopted this ASU using a prospective approach on January 1, 2017. This ASU will only be applicable to the extent that the Partnership determines its goodwill is impaired.
ASU 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business assists in determining whether a transaction should be accounted for as an acquisition or disposal of assets or a business. This ASU provides a screen that when substantially all of the fair value of the gross assets acquired, or disposed of, are concentrated in a single identifiable asset, or a group of similar identifiable assets, the assets will not be considered a business. If the screen is not met, the assets must include an input and a substantive process that together significantly contribute to the ability to create an output to be considered a business. The Partnership's adoption of this ASU on January 1, 2017,

using a prospective approach, could have a material impact on future consolidated financial statements as goodwill will not be allocated to divestitures or recorded on acquisitions that are not considered businesses.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

ASU 2016-16, Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory requires an entity to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs and eliminates the exception for an intra-entity transfer of an asset other than inventory. The Partnership adopted this ASU on January 1, 2017, using a modified retrospective approach, with no impact to its consolidated financial statements.

Accounting standards adopted in 2018. ASU 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash requires an entity to explain the changes in the total of cash, cash equivalents, restricted cash, and restricted cash equivalents on the statement of cash flows and to provide a reconciliation of the totals in that statement to the related captions in the balance sheet when the cash, cash equivalents, restricted cash, and restricted cash equivalents are presented in more than one line item on the balance sheet. The Partnership adopted this ASU using a retrospective approach on January 1, 2018. Adoption will not have a material impact on the consolidated financial statements.
ASU 2014-09, Revenue from Contracts with Customers (Topic 606) supersedes current revenue recognition requirements and industry-specific guidance, and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The Partnership adopted this new standard beginning January 1, 2018, using the modified retrospective method applied to contracts that were not completed as of January 1, 2018. The cumulative effect adjustment that will be recognized in the opening balance of equity and partners' capital will not be material. The Partnership implemented new business processes, procedures, controls and system changes to gather, categorize and analyze the necessary data for the accounting changes and expanded disclosure under Topic 606. Beginning in 2018, additional quantitative and qualitative disclosures will be required, including (i) expanded descriptions of the nature, amount, timing, and uncertainty of revenue and cash flows from contracts with customers, (ii) details of customer contract assets and liabilities, (iii) revenue from customers on a disaggregated basis, and (iv) comparative information presented under both Topic 605, Revenue Recognition ("Topic 605") and Topic 606. While the Partnership does not expect 2018 net income to be materially impacted by revenue recognition timing changes as a result of applying Topic 606, there will be significant changes to the presentation of revenues and related expenses recognized beginning January 1, 2018. The impacts of adopting Topic 606 include the following:

Transactions that will affect net income in 2018:

- Fee-based gathering / processing. Under Topic 605, fee revenue was recognized based on the rate in effect for the month of service, even when certain fees were charged on an upfront or limited-term basis. In addition, certain contingent fees were charged and recognized only when the customer did not meet the specified delivery minimums for the completed performance period. Under Topic 606, the Partnership will recognize revenue associated with upfront or limited-term fees over the expected period of benefit. In addition, the contingent fees will be estimated and recognized as the services are performed for the customer's delivered volumes. Differences between revenue recognized and amounts billed to customers will be recognized as contract assets or contract liabilities as appropriate. This will result in a change in the timing of revenue and changes to net income as a result of the consideration provisions. The magnitude of this change is dependent on future customer volumes subject to the impacted contracts.

- Cost of service rate adjustments. The Partnership receives fee revenue from contracts that require periodic rate redeterminations based upon the Partnership's costs of service. Under Topic 605, revenue was recognized based on the amounts billed to customers each period. Management is continuing to evaluate the proper accounting for these cost of service-based rate changes under Topic 606. The final conclusion about the accounting for these rate redeterminations could impact the cumulative effect adjustment that will be recorded effective January 1, 2018.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

- Aid in construction. Under certain midstream service contracts, the Partnership receives reimbursement for capital costs necessary to provide services to the customer (i.e., connection costs, etc.). These reimbursements historically have been reflected as a reduction to property, plant and equipment upon receipt (and a reduction to capital expenditures). Beginning in 2018, reimbursement of capital costs received from customers will be reflected as a contract liability (deferred revenue) upon receipt. The contract liability will be amortized to revenue over the expected period of benefit. The magnitude of this change to net income and to the Partnership's capital expenditures is dependent on the amount of aid in construction reimbursements received from customers.

Transactions with a presentation change beginning in 2018, but no effect on net income:

- Percentage of proceeds - gathering / processing. Under Topic 605, the Partnership recognized cost of product expense when the product was purchased from a producer to whom it provided midstream services and recognized revenue when the product was sold to a third party. Under Topic 606, in some instances where all or a percentage of the proceeds from the sale must be returned to the producer, the net margin from the purchase and sale transactions will be presented net within revenue because the Partnership is acting as the producer's agent in the sale. While reported product sales revenue and expense will be materially reduced, these presentation changes will not impact net income. The magnitude of this change is dependent on future customer volumes subject to the impacted contracts and commodity prices for those volumes.

- Noncash consideration - keep-whole and percentage of product agreements. The Partnership receives noncash consideration in the form of gas and/or NGL products in exchange for services under certain midstream contracts. Under Topic 605, the Partnership recognized revenue only upon the sale of the related products. Under Topic 606, the Partnership will recognize revenue for the products received as noncash consideration in exchange for the services provided to the customer, with the keep-whole noncash consideration value based on the net value of the NGLs over the replacement residue gas. The Partnership will also recognize both revenue and cost of product expense upon sale of the related products to a different customer. Reported revenue and expense are not expected to be materially impacted by this change, and there will be no impact to net income. The magnitude of this change is dependent on future customer volumes subject to the impacted contracts and commodity prices for those volumes.

- Wellhead purchase / sale incorporated into gathering / processing. Under Topic 605, the gas purchase cost was recognized as cost of product expense and any specified gathering or processing fees charged to the producer were recognized as revenue. Under Topic 606, the fees charged to the contract counterparty are recognized as adjustments to the purchase cost instead of revenue when such fees relate to services performed after control of the product transfers to the Partnership. While there is no impact to net income, it will result in decreased revenue and cost of product expense. The magnitude of this change is dependent on future customer volumes subject to the impacted contracts.

New accounting standards issued but not yet adopted. ASU 2016-02, Leases (Topic 842) requires lessees to recognize a lease liability and a right-of-use ("ROU") asset for all leases, including operating leases, with a term greater than 12 months on the balance sheet. This ASU modifies the definition of a lease and outlines the recognition, measurement, presentation, and disclosure of leasing arrangements by both lessees and lessors. Certain practical expedients will be used to implement the new standard and the Partnership will not reassess contracts that commenced prior to adoption. The Partnership will make a policy election not to recognize ROU assets or lease liabilities for leases with a term of 12 months or less. The Partnership is reviewing contracts for its portfolio of leased assets to assess the impact of adopting the new standard, which is expected to primarily affect other assets and other long-term liabilities. The

Partnership is also evaluating its systems, processes, and internal controls to facilitate compliance with this new standard. The Partnership will complete its evaluation in 2018 and adopt this new standard on January 1, 2019, using a modified retrospective approach for all comparative periods presented.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2. ACQUISITIONS AND DIVESTITURES

The following table presents the acquisitions completed by the Partnership during 2017, 2016 and 2015, and identifies the funding sources for such acquisitions:

thousands except unit and percent amounts	Acquisition Date	Percentage Acquired	Borrowings	Cash On Hand	Common Units Issued	Series A Preferred Units Issued
DBJV system [1]	03/02/2015	50 %	$ —	$ —	—	—
Springfield system [2]	03/14/2016	50.1 %	247,500	—	2,089,602	14,030,611
DBJV system [3]	03/17/2017	50 %	—	155,000	—	—

(1) The Partnership acquired Delaware Basin JV Gathering LLC ("DBJV") from Anadarko. At the time of acquisition, DBJV owned a 50% interest in a gathering system and related facilities (the "DBJV system") located in the Delaware Basin in Loving, Ward, Winkler and Reeves Counties, Texas. At the acquisition date, the Partnership estimated the future payment would be $282.8 million, the estimated net present value of which was $174.3 million. For further information, see DBJV acquisition—deferred purchase price obligation - Anadarko below.

(2) The Partnership acquired Springfield Pipeline LLC ("Springfield") from Anadarko for $750.0 million, consisting of $712.5 million in cash and the issuance of 1,253,761 of the Partnership's common units. Springfield owns a 50.1% interest in an oil gathering system and a gas gathering system. The Springfield oil and gas gathering systems (collectively, the "Springfield system") are located in Dimmit, La Salle, Maverick and Webb Counties in South Texas. The Partnership financed the cash portion of the acquisition through: (i) borrowings of $247.5 million on the Partnership's senior unsecured revolving credit facility ("RCF"), (ii) the issuance of 835,841 of the Partnership's common units to WGP and (iii) the issuance of Series A Preferred units to private investors. See Note 4 for further information regarding the Series A Preferred units.

(3) The Partnership acquired the Additional DBJV System Interest from a third party. See Property exchange below.

Property exchange. On March 17, 2017, the Partnership acquired the Additional DBJV System Interest from a third party in exchange for (a) the Partnership's 33.75% non-operated interest in two natural gas gathering systems located in northern Pennsylvania (the "Non-Operated Marcellus Interest"), commonly referred to as the Liberty and Rome systems, and (b) $155.0 million of cash consideration (collectively, the "Property Exchange"). The Partnership previously held a 50% interest in, and operated, the DBJV system.

The Property Exchange is reflected as a nonmonetary transaction whereby the acquired Additional DBJV System Interest is recorded at the fair value of the divested Non-Operated Marcellus Interest plus the $155.0 million of cash consideration. The Property Exchange resulted in a net gain of $125.7 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations. Results of operations attributable to the Property Exchange were included in the consolidated statements of operations beginning on the acquisition date in the first quarter of 2017.

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WESTERN GAS PARTNERS, LP
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2. ACQUISITIONS AND DIVESTITURES (CONTINUED)

DBJV acquisition - Deferred purchase price obligation - Anadarko. Prior to the Partnership's agreement with Anadarko to settle its deferred purchase price obligation early, the consideration that would have been paid by the Partnership for the March 2015 acquisition of DBJV from Anadarko consisted of a cash payment to Anadarko due on March 31, 2020. The cash payment would have been equal to (a) eight multiplied by the average of the Partnership's share of Net Earnings (as defined below) of DBJV for the calendar years 2018 and 2019, less (b) the Partnership's share of all capital expenditures incurred for DBJV between March 1, 2015, and February 29, 2020. Net Earnings was defined as all revenues less cost of product, operating expenses and property taxes, in each case attributable to DBJV on an accrual basis. In May 2017, the Partnership reached an agreement with Anadarko to settle this obligation with a cash payment to Anadarko of $37.3 million, which was equal to the estimated net present value of the obligation at March 31, 2017.
The following table summarizes the financial statement impact of the Deferred purchase price obligation - Anadarko:

	Deferred purchase price obligation - Anadarko	Estimated future payment obligation (1)
Balance at December 31, 2015	$188,674	$282,807
Accretion revision (2)	(7,747)	
Revision to Deferred purchase price obligation – Anadarko (3)	(139,487)	
Balance at December 31, 2016	41,440	56,455
Accretion expense (4)	71	
Revision to Deferred purchase price obligation – Anadarko (3)	(4,165)	
Settlement of the Deferred purchase price obligation – Anadarko	(37,346)	
Balance at December 31, 2017	$—	$—

(1) Calculated using Level 3 inputs.
(2) Financing-related accretion revisions were recorded in Interest expense in the consolidated statements of operations.
(3) Recorded as revisions within Common units in the consolidated balance sheets and consolidated statements of equity and partners' capital.
(4) Accretion expense was recorded as a charge to Interest expense in the consolidated statements of operations.

Helper and Clawson systems divestiture. During the second quarter of 2017, the Helper and Clawson systems, located in Utah, were sold to a third party, resulting in a net gain on sale of $16.3 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations.

Hugoton system divestiture. During the fourth quarter of 2016, the Hugoton system, located in Southwest Kansas and Oklahoma, was sold to a third party, resulting in a net loss on sale of $12.0 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations. The Partnership allocated $1.6 million in goodwill to this divestiture.

Dew and Pinnacle systems divestiture. During the third quarter of 2015, the Dew and Pinnacle systems in East Texas were sold to a third party, resulting in a net gain on sale of $77.3 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations. The Partnership allocated $5.1 million in goodwill to this divestiture.

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3. PARTNERSHIP DISTRIBUTIONS

The partnership agreement requires the Partnership to distribute all of its available cash (as defined in the partnership agreement) to unitholders of record on the applicable record date within 45 days of the end of each quarter. The Board of Directors declared the following cash distributions to the Partnership's common and general partner unitholders for the periods presented:

thousands except per-unit amounts Quarters Ended	Total Quarterly Distribution per Unit	Total Quarterly Cash Distribution	Date of Distribution
2015			
March 31	$ 0.725	$ 133,203	May 2015
June 30	0.750	139,736	August 2015
September 30	0.775	146,160	November 2015
December 31	0.800	152,588	February 2016
2016			
March 31	$ 0.815	$ 158,905	May 2016
June 30	0.830	162,827	August 2016
September 30	0.845	166,742	November 2016
December 31	0.860	170,657	February 2017
2017			
March 31	$ 0.875	$ 188,753	May 2017
June 30	0.890	207,491	August 2017
September 30	0.905	212,038	November 2017
December 31 (1)	0.920	216,586	February 2018

(1) The Board of Directors declared a cash distribution to the Partnership's unitholders for the fourth quarter of 2017 of $0.920 per unit, or $216.6 million in aggregate, including incentive distributions, but excluding distributions on Class C units (see Class C unit distributions below). The cash distribution was paid on February 13, 2018, to unitholders of record at the close of business on February 1, 2018.

Available cash. The amount of available cash (as defined in the partnership agreement) generally is all cash on hand at the end of the quarter, plus, at the discretion of the general partner, working capital borrowings made subsequent to the end of such quarter, less the amount of cash reserves established by the Partnership's general partner to provide for the proper conduct of the Partnership's business, including reserves to fund future capital expenditures; to comply with applicable laws, debt instruments or other agreements; or to provide funds for distributions to its unitholders and to its general partner for any one or more of the next four quarters. Working capital borrowings generally include borrowings made under a credit facility or similar financing arrangement. Working capital borrowings may only be those that, at the time of such borrowings, were intended to 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 unit distributions. The Class C units receive quarterly distributions at a rate equivalent to the Partnership's common units. The distributions are paid in the form of additional Class C units ("PIK Class C units") until the scheduled conversion date on March 1, 2020 (unless earlier converted), and the Class C units are disregarded with respect to distributions of the Partnership's available cash until they are converted into common units. The number of additional PIK Class C units to be issued in connection with a distribution payable on the Class C units is determined by dividing the corresponding distribution attributable to the Class C units by the volume-weighted-average price of the Partnership's common units for the ten days immediately preceding the payment date for the common unit distribution, less a 6% discount. The Partnership records the PIK Class C unit distributions at fair value at the time of issuance. This Level 2 fair value measurement uses the Partnership's unit price as a significant input in the determination of the fair value. See Note 4 for further discussion of the Class C units.

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WESTERN GAS PARTNERS, LP
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3. PARTNERSHIP DISTRIBUTIONS (CONTINUED)

Series A Preferred unit distributions. As further described in Note 4, the Partnership issued Series A Preferred units representing limited partner interests in the Partnership to private investors in 2016. The Series A Preferred unitholders received quarterly distributions in cash equal to $0.68 per Series A Preferred unit, subject to certain adjustments. The following table summarizes the Series A Preferred unitholders' cash distributions for the periods presented:

thousands except per-unit amounts Quarters Ended	Total Quarterly Distribution per Unit	Total Quarterly Cash Distribution	Date of Distribution
2016			
March 31 (1)	$ 0.68	$ 1,887	May 2016
June 30 (2)	0.68	14,082	August 2016
September 30	0.68	14,907	November 2016
December 31	0.68	14,908	February 2017
2017			
March 31	$ 0.68	$ 7,453	May 2017

(1) Quarterly per unit distribution prorated for the 18-day period during which 14,030,611 Series A Preferred units were outstanding during the first quarter of 2016.

(2) Full quarterly per unit distribution on 14,030,611 Series A Preferred units and quarterly per unit distribution prorated for the 77-day period during which 7,892,220 Series A Preferred units were outstanding during the second quarter of 2016.

On March 1, 2017, 50% of the outstanding Series A Preferred units converted into common units on a one-for-one basis, and on May 2, 2017, all remaining Series A Preferred units converted into common units on a one-for-one basis. Such converted common units were entitled to distributions made to common unitholders with respect to the quarter during which the applicable conversion occurred and did not include a prorated Series A Preferred unit distribution.

General partner interest and incentive distribution rights. As of December 31, 2017, the general partner was entitled to 1.5% of all quarterly distributions that the Partnership makes prior to its liquidation and, as the holder of the IDRs, was entitled to incentive distributions at the maximum distribution sharing percentage of 48.0% for all periods presented, after the minimum quarterly distribution and the target distribution levels had been achieved. The maximum distribution sharing percentage of 49.5% does not include any distributions that the general partner may receive on common units that it may acquire.

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4. EQUITY AND PARTNERS' CAPITAL

Equity offerings. Pursuant to the Partnership's registration statement filed with the SEC in August 2014 authorizing the issuance of up to an aggregate of $500.0 million of common units in a continuous offering program, during the year ended December 31, 2015, the Partnership issued 873,525 common units, at an average price of $66.61, generating proceeds of $57.4 million (net of $0.8 million for the underwriting discount and other offering expenses). Net proceeds were used for general partnership purposes, including funding capital expenditures. Gross proceeds generated during the three months and year ended December 31, 2015, were zero and $58.2 million, respectively. Commissions paid during the three months and year ended December 31, 2015, were zero and $0.6 million, respectively. During the years ended December 31, 2016 and 2017, the Partnership issued no common units under the registration statement filed in August 2014. In July 2017, the Partnership filed a registration statement with the SEC for the issuance of up to an aggregate of $500.0 million of common units pursuant to a new continuous offering program that has not yet been initiated.

Class C units. In November 2014, the Partnership issued 10,913,853 Class C units to APC Midstream Holdings, LLC ("AMH"), pursuant to a Unit Purchase Agreement with Anadarko and AMH. The Class C units were issued to partially fund the acquisition of DBM.
When issued, the Class C units were scheduled to convert into common units on a one-for-one basis on December 31, 2017. In February 2017, Anadarko elected to extend the conversion date of the Class C units to March 1, 2020. The Partnership can elect to convert the Class C units earlier or Anadarko can extend the conversion date again.
The Class C units were issued at a discount to the then-current market price of the common units into which they are convertible. This discount, totaling $34.8 million, represents a beneficial conversion feature, and at issuance, was reflected as an increase in common unitholders' capital and a decrease in Class C unitholder capital to reflect the fair value of the Class C units at issuance. The beneficial conversion feature is considered a non-cash distribution that is recognized from the date of issuance through the date of conversion, resulting in an increase in Class C unitholder capital and a decrease in common unitholders' capital as amortized. The beneficial conversion feature is amortized assuming the extended conversion date of March 1, 2020, using the effective yield method. The impact of the beneficial conversion feature amortization is also included in the calculation of earnings per unit.

Series A Preferred units. In connection with the closing of the Springfield acquisition on March 14, 2016, the Partnership issued 14,030,611 Series A Preferred units to private investors for a cash purchase price of $32.00 per unit, generating proceeds of $440.0 million (net of fees and expenses, but including a 2.0% transaction fee paid to the private investors). In April 2016, the Partnership issued an additional 7,892,220 Series A Preferred units pursuant to the full exercise of an option granted in connection with the Series A units issuance in March 2016, generating net proceeds of $246.9 million. Pursuant to an agreement between the Partnership and the holders of the Series A Preferred units, 50% of the Series A Preferred units converted into common units on a one-for-one basis on March 1, 2017, and all remaining Series A Preferred units converted into common units on a one-for-one basis on May 2, 2017. The Partnership has an effective registration statement with the SEC relating to the public resale of the common units issued upon conversion of the Series A Preferred units.
The Series A Preferred units were issued at a discount to the then-current market price of the common units into which they were convertible. This discount, totaling $93.4 million, represented a beneficial conversion feature, and at issuance, was reflected as an increase in common unitholders' capital and a decrease in Series A Preferred unitholders' capital to reflect the fair value of the Series A Preferred units on the date of issuance. The beneficial conversion feature was considered a non-cash distribution that was recognized from the date of issuance through the date of conversion, resulting in an increase in Series A Preferred unitholders' capital and a decrease in common unitholders' capital as amortized. The beneficial conversion feature was amortized using the effective yield method. The impact of the beneficial conversion feature amortization is also included in the calculation of earnings per unit. For the year

ended December 31, 2017, the amortization for the beneficial conversion feature of the Series A Preferred units was $62.3 million.

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WESTERN GAS PARTNERS, LP
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4. EQUITY AND PARTNERS' CAPITAL (CONTINUED)

Partnership interests. The Partnership's common units are listed on the New York Stock Exchange under the symbol "WES."
The following table summarizes the common, Class C, Series A Preferred and general partner units issued during the years ended December 31, 2017 and 2016:

	Common Units	Class C Units	Series A Preferred Units	General Partner Units	Total
Balance at December 31, 2015	128,576,965	11,411,862	—	2,583,068	142,571,895
PIK Class C units	—	946,261	—	—	946,261
Springfield acquisition	2,089,602	—	14,030,611	—	16,120,213
April 2016 Series A units issuance	—	—	7,892,220	—	7,892,220
Long-Term Incentive Plan award vestings	5,403	—	—	—	5,403
Balance at December 31, 2016	130,671,970	12,358,123	21,922,831	2,583,068	167,535,992
PIK Class C units	—	885,760	—	—	885,760
Conversion of Series A Preferred units	21,922,831	—	(21,922,831)	—	—
Long-Term Incentive Plan award vestings	7,304	—	—	—	7,304
Balance at December 31, 2017	152,602,105	13,243,883	—	2,583,068	168,429,056

Holdings of Partnership equity. As of December 31, 2017, WGP held 50,132,046 common units, representing a 29.8% limited partner interest in the Partnership, and, through its ownership of the general partner, WGP indirectly held 2,583,068 general partner units, representing a 1.5% general partner interest in the Partnership, and 100% of the IDRs. As of December 31, 2017, other subsidiaries of Anadarko collectively held 2,011,380 common units and 13,243,883 Class C units, representing an aggregate 9.1% limited partner interest in the Partnership. As of December 31, 2017, the public held 100,458,679 common units, representing the remaining 59.6% limited partner interest in the Partnership.

Net income (loss) per unit for common units. Net income (loss) attributable to the Partnership assets acquired from Anadarko for periods prior to the Partnership's acquisition of the Partnership assets is not allocated to the unitholders for purposes of calculating net income (loss) per common unit. Net income (loss) attributable to Western Gas Partners, LP earned on and subsequent to the date of acquisition of the Partnership assets is allocated as follows:

General partner. The general partner's allocation is equal to cash distributions plus its portion of undistributed earnings or losses. Specifically, net income equal to the amount of available cash (as defined by the partnership agreement) is allocated to the general partner consistent with actual cash distributions and capital account allocations, including incentive distributions. Undistributed earnings (net income in excess of distributions) or undistributed losses (available cash in excess of net income) are then allocated to the general partner in accordance with its weighted-average ownership percentage during each period.

Series A Preferred unitholders. The Series A Preferred units were not considered a participating security as they only had distribution rights up to the specified per-unit quarterly distribution and had no rights to the Partnership's undistributed earnings and losses. As such, the Series A Preferred unitholders' allocation was equal to their cash distribution plus the amortization of the Series A Preferred units beneficial conversion feature (see Series A Preferred units above).

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WESTERN GAS PARTNERS, LP
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4. EQUITY AND PARTNERS' CAPITAL (CONTINUED)

Common and Class C unitholders. The Class C units are considered a participating security because they participate in distributions with common units according to a predetermined formula (see Note 3). The common and Class C unitholders' allocation is equal to their cash distributions plus their respective portions of undistributed earnings or losses. Specifically, net income equal to the amount of available cash (as defined by the partnership agreement) is allocated to the common and Class C unitholders consistent with actual cash distributions and capital account allocations. Undistributed earnings or undistributed losses are then allocated to the common and Class C unitholders in accordance with their respective weighted-average ownership percentages during each period. The common unitholder allocation also includes the impact of the amortization of the Series A Preferred units and Class C units beneficial conversion features. The Class C unitholder allocation is similarly impacted by the amortization of the Class C units beneficial conversion feature (see Class C units above).

Calculation of net income (loss) per unit. Basic net income (loss) per common unit is calculated by dividing the net income (loss) attributable to common unitholders by the weighted-average number of common units outstanding during the period. The common units issued in connection with acquisitions and equity offerings are included on a weighted-average basis for periods they were outstanding. Diluted net income (loss) per common unit is calculated by dividing the sum of (i) the net income (loss) attributable to common units adjusted for distributions on the Series A Preferred units and a reallocation of the common and Class C limited partners' interest in net income (loss) assuming, prior to the actual conversion, conversion of the Series A Preferred units into common units, and (ii) the net income (loss) attributable to the Class C units as a participating security, by the sum of the weighted-average number of common units outstanding plus the dilutive effect of (i) the weighted-average number of outstanding Class C units and (ii) the weighted-average number of common units outstanding assuming, prior to the actual conversion, conversion of the Series A Preferred units.
The following table illustrates the Partnership's calculation of net income (loss) per unit for common units:

	Year Ended December 31,		
thousands except per-unit amounts	2017	2016	2015
Net income (loss) attributable to Western Gas Partners, LP	$567,483	$591,331	$4,106
Pre-acquisition net (income) loss allocated to Anadarko	—	(11,326)	(79,386)
Series A Preferred units interest in net (income) loss [1]	(42,373)	(76,893)	—
General partner interest in net (income) loss	(303,835)	(236,561)	(180,996)
Common and Class C limited partners' interest in net income (loss)	$221,275	$266,551	$(256,276)
Net income (loss) allocable to common units [1]	$192,066	$226,611	$(250,210)
Net income (loss) allocable to Class C units [1]	29,209	39,940	(6,066)
Common and Class C limited partners' interest in net income (loss)	$221,275	$266,551	$(256,276)
Net income (loss) per unit			
Common units – basic and diluted [2]	$1.30	$1.74	$(1.95)
Weighted-average units outstanding			
Common units – basic and diluted	147,194	130,253	128,345
Excluded due to anti-dilutive effect:			
Class C units [2]	12,776	11,945	11,114
Series A Preferred units assuming conversion to common units [2]	5,406	16,860	—

[1] Adjusted to reflect amortization of the beneficial conversion features.
[2] The impact of Class C units and the conversion of Series A Preferred units would be anti-dilutive for all periods presented. On March 1, 2017, 50% of the outstanding Series A Preferred units converted into common units on a one-for-one basis, and on May 2, 2017, all remaining Series A Preferred units converted into common units on a

one-for-one basis.

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5. TRANSACTIONS WITH AFFILIATES

Affiliate transactions. Revenues from affiliates include amounts earned by the Partnership from services provided to Anadarko as well as from the sale of residue and NGLs to Anadarko. In addition, the Partnership purchases natural gas from an affiliate of Anadarko pursuant to gas purchase agreements. Operation and maintenance expense includes amounts accrued for or paid to affiliates for the operation of the Partnership assets, whether in providing services to affiliates or to third parties, including field labor, measurement and analysis, and other disbursements. A portion of the Partnership's general and administrative expenses is paid by Anadarko, which results in affiliate transactions pursuant to the reimbursement provisions of the Partnership's omnibus agreement. Affiliate expenses do not bear a direct relationship to affiliate revenues, and third-party expenses do not bear a direct relationship to third-party revenues. See Note 2 for further information related to contributions of assets to the Partnership by Anadarko.

Cash management. Anadarko operates a cash management system whereby excess cash from most of its subsidiaries' separate bank accounts is generally swept to centralized accounts. Prior to the Partnership's acquisition of the Partnership assets, third-party sales and purchases related to such assets were received or paid in cash by Anadarko within its centralized cash management system. The outstanding affiliate balances were entirely settled through an adjustment to net investment by Anadarko in connection with the acquisition of the Partnership assets. Subsequent to the acquisition of Partnership assets from Anadarko, transactions related to such assets are cash-settled directly with third parties and with Anadarko affiliates. Chipeta cash settles its transactions directly with third parties and Anadarko, as well as with the other subsidiaries of the Partnership.

Note receivable - Anadarko. Concurrently with the closing of the Partnership's May 2008 initial public offering, the Partnership loaned $260.0 million to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.50%, payable quarterly. The fair value of the note receivable from Anadarko was $325.2 million and $313.3 million at December 31, 2017 and 2016, respectively. The fair value of the note reflects consideration of credit risk and any premium or discount for the differential between the stated interest rate and quarter-end market interest rate, based on quoted market prices of similar debt instruments. Accordingly, the fair value of the note receivable from Anadarko is measured using Level 2 inputs.

Commodity price swap agreements. The Partnership has commodity price swap agreements with Anadarko to mitigate exposure to a majority of the commodity price risk inherent in its percent-of-proceeds and keep-whole contracts. Notional volumes for each of the commodity price swap agreements are not specifically defined. Instead, the commodity price swap agreements apply to the actual volume of natural gas, condensate and NGLs purchased and sold. The commodity price swap agreements do not satisfy the definition of a derivative financial instrument and, therefore, are not required to be measured at fair value.

5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

The following table summarizes gains and losses upon settlement of commodity price swap agreements recognized in the consolidated statements of operations:

	Year Ended December 31,		
thousands	2017	2016	2015
Gains (losses) on commodity price swap agreements related to sales: [1]			
Natural gas sales	$19,924	$11,116	$45,978
Natural gas liquids sales	(21,722)	59,918	145,258
Total	(1,798)	71,034	191,236
Gains (losses) on commodity price swap agreements related to purchases [2]	2,446	(42,577)	(124,944)
Net gains (losses) on commodity price swap agreements	$648	$28,457	$66,292

(1) Reported in affiliate Natural gas and natural gas liquids sales in the consolidated statements of operations in the period in which the related sale is recorded.

(2) Reported in Cost of product in the consolidated statements of operations in the period in which the related purchase is recorded.

Swap agreements - DJ Basin complex, Hugoton system and MGR assets. On June 25, 2015, the Partnership extended its commodity price swap agreements with Anadarko for the DJ Basin complex from July 1, 2015, through December 31, 2015, and for the Hugoton system from October 1, 2015, through December 31, 2015. On December 8, 2015, the commodity price swap agreements with Anadarko for the DJ Basin complex and Hugoton system were extended from January 1, 2016, through December 31, 2016. On December 1, 2016, the commodity price swap agreements with Anadarko for the DJ Basin complex and the MGR assets were extended from January 1, 2017 through December 31, 2017. On December 20, 2017, the commodity price swap agreements with Anadarko for the DJ Basin complex and the MGR assets were extended from January 1, 2018 through December 31, 2018.
Revenues or costs attributable to volumes settled during the respective extension period, at the applicable market price in the tables below, are recognized in the consolidated statements of operations. The Partnership also records a capital contribution from Anadarko in the Partnership's consolidated statements of equity and partners' capital for an amount equal to (i) the amount by which the swap price recognized as revenue exceeds the applicable market price in the tables below, minus (ii) the amount by which the swap price recognized as cost of product exceeds the market price in the tables below. For the years ended December 31, 2017, 2016 and 2015, the capital contributions from Anadarko were $58.6 million, $45.8 million and $18.4 million, respectively. The tables below summarize the swap prices for the extension periods compared to the forward market prices as of the various agreement dates.

	DJ Basin Complex				
per barrel except natural gas	2015 - 2018 Swap Prices	2015 Market Prices [1]	2016 Market Prices [1]	2017 Market Prices [1]	2018 Market Prices [1]
Ethane	$18.41	$ 1.96	$ 0.60	$ 5.09	$ 5.41
Propane	47.08	13.10	10.98	18.85	28.72
Isobutane	62.09	19.75	17.23	26.83	32.92
Normal butane	54.62	18.99	16.86	26.20	32.71
Natural gasoline	72.88	52.59	26.15	41.84	48.04
Condensate	76.47	52.59	34.65	45.40	49.36
Natural gas (per MMBtu)	5.96	2.75	2.11	3.05	2.21

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5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

	Hugoton System [2]		
per barrel except natural gas	2015 - 2016 Swap Prices	2015 Market Prices [1]	2016 Market Prices [1]
Condensate	$78.61	$ 32.56	$ 18.81
Natural gas (per MMBtu)	5.50	2.74	2.12

	MGR Assets			
per barrel except natural gas	2015 Swap Prices	2016 - 2018 Swap Prices	2017 Market Prices [1]	2018 Market Prices [1]
Ethane	$23.41	$23.11	$ 4.08	$ 2.52
Propane	52.99	52.90	19.24	25.83
Isobutane	74.02	73.89	25.79	30.03
Normal butane	65.04	64.93	25.16	29.82
Natural gasoline	81.82	81.68	45.01	47.25
Condensate	81.82	81.68	53.55	56.76
Natural gas (per MMBtu)	4.66	4.87	3.05	2.21

(1) Represents the New York Mercantile Exchange forward strip price as of June 25, 2015, December 8, 2015, December 1, 2016, and December 20, 2017, for the 2015 Market Prices, 2016 Market Prices, 2017 Market Prices, and 2018 Market Prices, respectively, adjusted for product specification, location, basis and, in the case of NGLs, transportation and fractionation costs.

(2) The Hugoton system was sold in October 2016. See Note 2.

Gathering and processing agreements. The Partnership has significant gathering and processing arrangements with affiliates of Anadarko on a majority of its systems. The Partnership's natural gas gathering, treating and transportation throughput (excluding equity investment throughput) attributable to production owned or controlled by Anadarko was 34%, 37% and 53% for the years ended December 31, 2017, 2016 and 2015, respectively. The Partnership's natural gas processing throughput (excluding equity investment throughput) attributable to production owned or controlled by Anadarko was 41%, 54% and 51% for the years ended December 31, 2017, 2016 and 2015, respectively. The Partnership's crude oil, NGL and produced water gathering, treating, transportation and disposal throughput (excluding equity investment throughput) attributable to production owned or controlled by Anadarko was 56%, 65%, and 100% for the years ended December 31, 2017, 2016 and 2015, respectively. Prior to January 1, 2016, Springfield's contracts were with a subsidiary of Anadarko who contracted with third parties. Effective January 1, 2016, Springfield's contracts are with both a subsidiary of Anadarko and third parties directly.

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

Acquisitions from Anadarko. On March 14, 2016, the Partnership acquired Springfield from Anadarko, and on March 2, 2015, the Partnership acquired DBJV from Anadarko. (see Note 2).

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5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Omnibus agreement. Pursuant to the omnibus agreement, Anadarko performs centralized corporate functions for the Partnership, such as legal; accounting; treasury; cash management; investor relations; insurance administration and claims processing; risk management; health, safety and environmental; information technology; human resources; credit; payroll; internal audit; tax; marketing; and midstream administration. Anadarko, in accordance with the partnership and omnibus agreements, determines, in its reasonable discretion, amounts to be reimbursed by the Partnership in exchange for services provided under the omnibus agreement. See Summary of affiliate transactions below.
The following table summarizes the amounts the Partnership reimbursed to Anadarko:

	Year Ended December 31,		
thousands	2017	2016	2015
General and administrative expenses	$31,733	$29,360	$22,896
Public company expenses	9,379	8,410	8,950
Total reimbursement	$41,112	$37,770	$31,846

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

Tax sharing agreement. Pursuant to a tax sharing agreement, the Partnership reimburses Anadarko for its estimated share of taxes from all forms of taxation, excluding taxes imposed by the United States. Taxes for which the Partnership reimburses Anadarko include state taxes attributable to the Partnership’s income, which are directly borne by Anadarko through its filing of a combined or consolidated tax return with respect to periods beginning on and subsequent to the acquisition of the Partnership assets from Anadarko. Anadarko may use its own tax attributes to reduce or eliminate the tax liability of its combined or consolidated group, which may include the Partnership as a member. However, under this circumstance, the Partnership nevertheless is required to reimburse Anadarko for its allocable share of taxes that would have been owed had tax attributes not been available to Anadarko.

Allocation of costs. For periods prior to the Partnership’s acquisition of the Partnership assets, the consolidated financial statements 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. This management services fee was allocated to the Partnership based on its proportionate share of Anadarko’s assets and revenues or other contractual arrangements. Management believes these allocation methodologies are reasonable.
The employees supporting the Partnership’s operations are employees of Anadarko. Anadarko allocates costs to the Partnership for its share of personnel costs, including costs associated with equity-based compensation plans, non-contributory defined pension and postretirement plans and defined contribution savings plans pursuant to the omnibus agreement and services and secondment agreement. In general, the Partnership’s reimbursement to Anadarko under the omnibus agreement or services and secondment agreements is either (i) on an actual basis for direct expenses Anadarko and the general partner incur on behalf of the Partnership, or (ii) based on an allocation of salaries and related employee benefits between the Partnership, the general partner and Anadarko based on estimates of time

spent on each entity's business and affairs. Most general and administrative expenses charged to the Partnership by Anadarko are attributed to the Partnership on an actual basis, and do not include any mark-up or subsidy component. With respect to allocated costs, management believes the allocation method employed by Anadarko is reasonable. Although it is not practicable to determine what the amount of these direct and allocated costs would be if the Partnership were to directly obtain these services, management believes that aggregate costs charged to the Partnership by Anadarko are reasonable.

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5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

WES LTIP. The general partner awards phantom units under the WES LTIP primarily to its independent directors, but also from time to time to its executive officers and Anadarko employees performing services for the Partnership. The phantom units awarded to the independent directors vest one year from the grant date, while all other awards are subject to graded vesting over a three-year service period. Compensation expense is recognized over the vesting period and was $0.4 million for each of the years ended December 31, 2017 and 2016, and $0.5 million for the year ended December 31, 2015. As of December 31, 2017, there was $0.2 million of unrecognized compensation expense attributable to the outstanding awards under the WES LTIP, all of which will be realized by the Partnership, and which is expected to be recognized over a weighted-average period of 0.4 years.
The following table summarizes WES LTIP award activity for the years ended December 31, 2017, 2016 and 2015:

	2017		2016		2015	
	Weighted-Average Grant-Date Fair Value	Units	Weighted-Average Grant-Date Fair Value	Units	Weighted-Average Grant-Date Fair Value	Units
Phantom units outstanding at beginning of year	$ 49.30	7,304	$ 68.78	5,477	$ 60.74	9,522
Vested	49.30	(7,304)	68.78	(5,477)	60.69	(9,257)
Granted	55.73	7,180	49.30	7,304	69.10	5,212
Phantom units outstanding at end of year	55.73	7,180	49.30	7,304	68.78	5,477

WGP LTIP and Anadarko Incentive Plans. For the years ended December 31, 2017, 2016 and 2015, general and administrative expenses included $4.6 million, $5.2 million and $3.9 million, respectively, of equity-based compensation expense, allocated to the Partnership by Anadarko, for awards granted to the executive officers of the general partner and other employees under the WGP LTIP and the Anadarko Incentive Plans. Of these amounts, $4.6 million, $4.2 million and $3.6 million for the years ended December 31, 2017, 2016 and 2015, respectively, are reflected as contributions to partners' capital in the Partnership's consolidated statements of equity and partners' capital. As of December 31, 2017, the Partnership estimated that $13.2 million of estimated unrecognized compensation expense attributable to the Anadarko Incentive Plans will be allocated to the Partnership over a weighted-average period of 2.5 years.

Equipment purchases and sales. The following table summarizes the Partnership's purchases from and sales to Anadarko of pipe and equipment:

	Year Ended December 31,					
	2017	2016	2015	2017	2016	2015
thousands	Purchases			Sales		
Cash consideration	$3,910	$3,965	$10,903	$—	$623	$925
Net carrying value	(5,283)	(3,366)	(6,318)	—	(605)	(972)
Partners' capital adjustment	$(1,373)	$599	$4,585	$—	$18	$(47)

Contributions in aid of construction costs from affiliates. On certain of the Partnership's capital projects, Anadarko is obligated to reimburse the Partnership for all or a portion of project capital expenditures. The majority of such arrangements are associated with projects related to pipeline construction activities and production well tie-ins. The cash receipts resulting from such reimbursements are presented as "Contributions in aid of construction costs from affiliates" within the investing section of the Partnership's consolidated statements of cash flows. See Accounting standards adopted in 2018 in Note 1 for a discussion of the expected impact the adoption of Topic 606 will have on future aid in construction costs.

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5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Summary of affiliate transactions. The following table summarizes material affiliate transactions. See Note 2 for discussion of affiliate acquisitions and related funding.

	Year ended December 31,		
thousands	2017	2016	2015
Revenues and other [1]	$1,365,318	$1,228,232	$1,220,639
Equity income, net – affiliates [1]	85,194	78,717	71,251
Cost of product [1]	86,010	80,455	167,354
Operation and maintenance [2]	72,489	72,330	77,061
General and administrative [3]	39,130	38,066	33,903
Operating expenses	197,629	190,851	278,318
Interest income [4]	16,900	16,900	16,900
Interest expense [5]	71	(7,747)	14,398
Settlement of the Deferred purchase price obligation – Anadarko [6]	(37,346)	—	—
Proceeds from the issuance of common units, net of offering expenses [7]	—	25,000	—
Distributions to unitholders [8]	452,777	382,711	314,200
Above-market component of swap agreements with Anadarko	58,551	45,820	18,449

(1) Represents amounts earned or incurred on and subsequent to the date of the acquisition of Partnership assets, as well as amounts earned or incurred by Anadarko on a historical basis related to the Partnership assets prior to the acquisition of such assets, recognized under gathering, treating or processing agreements, and purchase and sale agreements.
(2) Represents expenses incurred on and subsequent to the date of the acquisition of Partnership assets, as well as expenses incurred by Anadarko on a historical basis related to the Partnership assets prior to the acquisition of such assets.
(3) Represents general and administrative expense incurred on and subsequent to the date of the acquisition of Partnership assets, as well as a management services fee for reimbursement of expenses incurred by Anadarko for periods prior to the acquisition of the Partnership assets by the Partnership. These amounts include equity-based compensation expense allocated to the Partnership by Anadarko (see WES LTIP and WGP LTIP and Anadarko Incentive Plans within this Note 5).
(4) Represents interest income recognized on the note receivable from Anadarko.
(5) Includes amounts related to the Deferred purchase price obligation - Anadarko (see Note 2 and Note 12).
(6) Represents the cash payment to Anadarko for the settlement of the Deferred purchase price obligation - Anadarko (see Note 2).
(7) Represents proceeds from the issuance of 835,841 common units to WGP as partial funding for the acquisition of Springfield (see Note 2).
(8) Represents distributions paid under the partnership agreement (see Note 3 and Note 4).

Concentration of credit risk. Anadarko was the only customer from whom revenues exceeded 10% of the Partnership’s consolidated revenues for all periods presented in the consolidated statements of operations.

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6. INCOME TAXES

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

	Year Ended December 31,		
thousands	2017	2016	2015
Current income tax expense (benefit)			
Federal income tax expense (benefit)	$—	$4,477	$32,422
State income tax expense (benefit)	2,408	1,340	1,764
Total current income tax expense (benefit)	2,408	5,817	34,186
Deferred income tax expense (benefit)			
Federal income tax expense (benefit)	—	1,622	10,251
State income tax expense (benefit)	2,458	933	1,095
Total deferred income tax expense (benefit)	2,458	2,555	11,346
Total income tax expense (benefit)	$4,866	$8,372	$45,532

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

	Year Ended December 31,		
thousands except percentages	2017	2016	2015
Income (loss) before income taxes	$583,084	$610,666	$59,739
Statutory tax rate	— %	— %	— %
Tax computed at statutory rate	$—	$—	$—
Adjustments resulting from:			
Federal taxes on income attributable to Partnership assets pre-acquisition	—	6,162	42,823
State taxes on income attributable to Partnership assets pre-acquisition (net of federal benefit)	—	117	298
Texas margin tax expense (benefit) [1]	4,866	2,093	2,411
Income tax expense (benefit)	$4,866	$8,372	$45,532
Effective tax rate	1 %	1 %	76 %

(1) Includes a reduction of $2.2 million in deferred state income taxes for the year ended December 31, 2015. Texas House Bill 32, signed into law in June 2015, reduced the Texas margin tax rates by 0.25%. The law became effective January 1, 2016. The Partnership is required to include the impact of the law change on its deferred state income taxes in the period enacted.

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

	December 31,	
thousands	2017	2016
Depreciable property	$(7,676)	$(4,976)
Credit carryforwards	448	498
Other intangible assets	(189)	(1,928)
Other	8	4
Net long-term deferred income tax liabilities	$(7,409)	$(6,402)

Credit carryforwards, which are available for use on future income tax returns, consist of $0.4 million of state income tax credits that expire in 2026.

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7. PROPERTY, PLANT AND EQUIPMENT

A summary of the historical cost of property, plant and equipment is as follows:

		December 31,	
thousands	Estimated Useful Life	2017	2016
Land	n/a	$4,450	$4,012
Gathering systems and processing complexes	3 to 47 years	7,114,701	6,462,053
Pipelines and equipment	15 to 45 years	137,644	139,646
Assets under construction	n/a	577,914	226,626
Other	3 to 40 years	36,393	29,605
Total property, plant and equipment		7,871,102	6,861,942
Accumulated depreciation		2,140,211	1,812,010
Net property, plant and equipment		$5,730,891	$5,049,932

The cost of property classified as “Assets under construction” is excluded from capitalized costs being depreciated. These amounts represent property that is not yet suitable to be placed into productive service as of the respective balance sheet date.

Impairments. During 2017, the Partnership recognized impairments of $178.4 million, including an impairment of $158.8 million at the Granger complex, which was impaired to its estimated fair value of $48.5 million using the income approach and Level 3 fair value inputs, due to a reduced throughput fee as a result of a producer’s bankruptcy. The remaining $19.6 million of impairments was primarily related to (i) an $8.2 million impairment due to the cancellation of a plant project at the Hilight system, (ii) a $3.7 million impairment at the Granger straddle plant, which was impaired to its estimated salvage value of $0.6 million using the income approach and Level 3 fair value inputs, (iii) a $3.1 million impairment of the Fort Union equity investment (see Note 9), (iv) a $2.0 million impairment of an idle facility in northeast Wyoming, which was impaired to its estimated salvage value of $0.4 million using the market approach and Level 3 fair value inputs, and (v) the cancellation of a pipeline project in West Texas.
During 2016, the Partnership recognized impairments of $15.5 million, including an impairment of $6.1 million at the Newcastle system, which was impaired to its estimated fair value of $3.1 million using the income approach and Level 3 fair value inputs, due to a reduction in estimated future cash flows caused by the low commodity price environment. Also during 2016, the Partnership recognized impairments of $9.4 million, primarily related to the cancellation of projects at the DJ Basin complex and Springfield and DBJV systems, and the abandonment of compressors at the MIGC system.
During 2015, the Partnership recognized impairments of $515.5 million, primarily due to impairments of $280.2 million at the Red Desert complex and $220.9 million at the Hilight system. Using the income approach and Level 3 fair value inputs, the Red Desert complex was impaired to its estimated salvage value of $6.3 million and the Hilight system was impaired to its estimated fair value of $28.8 million. These impairments were triggered by a reduction in estimated future cash flows caused by the low commodity price environment and resulting reduced producer drilling activity and related throughput. Also during 2015, the Partnership recognized impairments of $14.4 million, primarily due to (i) the abandonment of compressors at the MIGC system and (ii) the cancellation of projects at the Non-Operated Marcellus Interest systems and the Brasada, Red Desert and DJ Basin complexes.

8. GOODWILL AND INTANGIBLES

Goodwill. 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, goodwill represents the allocated portion of Anadarko's midstream goodwill attributed to the Partnership assets acquired from Anadarko. The carrying value of Anadarko's midstream goodwill represents the excess of the purchase price paid to a third-party entity over the estimated fair value of the identifiable assets acquired and liabilities assumed by Anadarko. Accordingly, the Partnership's allocated goodwill balance does not represent, and in some cases is significantly different from, the difference between the consideration the Partnership paid for its acquisitions from Anadarko and the fair value of such net assets on their respective acquisition dates.
Goodwill is evaluated for impairment annually (see Note 1). Estimating the fair value of the reporting units was not necessary based on the qualitative evaluation as of October 1, 2017, and no goodwill impairment has been recognized in these consolidated financial statements. Qualitative factors were also assessed in the fourth quarter of 2017 to review any changes in circumstances subsequent to the annual test, including changes in commodity prices. This assessment also indicated no impairment.

Other intangible assets. The intangible asset balance on the consolidated balance sheets includes the fair value, net of amortization, of (i) contracts assumed by the Partnership in connection with the Platte Valley acquisition in February 2011, which are being amortized on a straight-line basis over 50 years, (ii) interconnect agreements at Chipeta entered into in November 2012, which are being amortized on a straight-line basis over 10 years, and (iii) contracts assumed by the Partnership in connection with the DBM acquisition in November 2014, which are being amortized on a straight-line basis over 30 years.
The Partnership assesses intangible assets for impairment together with related underlying long-lived assets whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. See Property, plant and equipment in Note 1 for further discussion of management's process to evaluate potential impairment of long-lived assets. No intangible asset impairment has been recognized in these consolidated financial statements.
The following table presents the gross carrying amount and accumulated amortization of other intangible assets:

	December 31,	
thousands	2017	2016
Gross carrying amount	$868,035	$868,035
Accumulated amortization	(92,766)	(64,337)
Other intangible assets	$775,269	$803,698

Amortization expense for intangible assets was $28.4 million for each of the years ended December 31, 2017 and 2016, and $28.2 million for the year ended December 31, 2015. An estimated $28.4 million of intangible asset amortization will be recorded for each of the next five years.

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9. EQUITY INVESTMENTS

The following table presents the activity in the Partnership’s equity investments for the years ended December 31, 2017 and 2016:

	Equity Investments							
thousands	Fort Union [(1)]	White Cliffs [(2)]	Rendezvous [(3)]	Mont Belvieu JV [(4)]	TEG [(5)]	TEP [(6)]	FRP [(7)]	Total
Balance at December 31, 2015	$17,122	$50,439	$ 50,913	$117,089	$16,283	$194,803	$172,238	$618,887
Investment earnings (loss), net of amortization	608	13,858	1,931	26,204	708	16,683	18,725	78,717
Contributions	—	441	—	—	166	(580)	—	27
Distributions	(1,543)	(13,277)	(3,873)	(26,243)	(730)	(16,934)	(19,585)	(82,185)
Distributions in excess of cumulative earnings [(8)]	(3,354)	(4,142)	(2,232)	(4,245)	(581)	(4,778)	(1,906)	(21,238)
Balance at December 31, 2016	$12,833	$47,319	$ 46,739	$112,805	$15,846	$189,194	$169,472	$594,208
Investment earnings (loss), net of amortization	3,821	12,547	1,144	29,444	3,350	17,387	17,501	85,194
Impairment expense [(9)]	(3,110)	—	—	—	—	—	—	(3,110)
Contributions	—	277	—	—	—	107	—	384
Distributions	(4,217)	(11,965)	(3,085)	(29,482)	(3,317)	(17,639)	(17,675)	(87,380)
Distributions in excess of cumulative earnings [(8)]	(2,297)	(3,233)	(2,270)	(2,468)	—	(10,074)	(2,743)	(23,085)
Balance at December 31, 2017	$7,030	$44,945	$ 42,528	$110,299	$15,879	$178,975	$166,555	$566,211

(1) The Partnership has a 14.81% interest in Fort Union, a joint venture that owns a gathering pipeline and treating facilities in the Powder River Basin. Anadarko is the construction manager and physical operator of the Fort Union facilities. Certain business decisions, including, but not limited to, decisions with respect to significant expenditures or contractual commitments, annual budgets, material financings, dispositions of assets or amending the owners’ firm gathering agreements, require 65% or unanimous approval of the owners.

(2) The Partnership has a 10% interest in White Cliffs, a limited liability company that owns a crude oil pipeline that originates in Platteville, Colorado and terminates in Cushing, Oklahoma. The third-party majority owner is the manager of the White Cliffs operations. Certain business decisions, including, but not limited to, approval of annual budgets and decisions with respect to significant expenditures, contractual commitments, acquisitions, material financings, dispositions of assets or admitting new members, require more than 75% approval of the members.

(3) The Partnership has a 22% interest in Rendezvous, a limited liability company that operates gas gathering facilities in Southwestern Wyoming. Certain business decisions, including, but not limited to, decisions with respect to significant expenditures or contractual commitments, annual budgets, material financings, dispositions of assets or amending the members’ gas servicing agreements, require unanimous approval of the members.

(4) The Partnership has a 25% interest in the Mont Belvieu JV, an entity formed to design, construct, and own two fractionation trains located in Mont Belvieu, Texas. A third party is the operator of the Mont Belvieu JV fractionation trains. Certain business decisions, including, but not limited to, decisions with respect to the execution of contracts, settlements, disposition of assets, or the creation, appointment, or removal of officer

positions require 50% or unanimous approval of the owners.

(5) The Partnership has a 20% interest in TEG, which owns two NGL gathering systems that link natural gas processing plants to TEP. Midcoast Energy Partners, L.P., a wholly-owned subsidiary of Enbridge, Inc., is the operator of the two gathering systems. Certain business decisions, including, but not limited to, decisions with respect to the execution of contracts, settlements, disposition of assets, or the delegation, creation, appointment, or removal of officer positions require more than 50% approval of the members.

(6) The Partnership has a 20% interest in TEP, which owns an NGL pipeline that originates in Skellytown, Texas and extends to Mont Belvieu, Texas. Enterprise Products Operating LLC (“Enterprise”) is the operator of TEP. Certain business decisions, including, but not limited to, decisions with respect to the execution of contracts, settlements, disposition of assets, or the creation, appointment, or removal of officer positions require more than 50% approval of the members.

(7) The Partnership has a 33.33% interest in FRP, which owns an NGL pipeline that extends from Weld County, Colorado to Skellytown, Texas. Enterprise is the operator of FRP. Certain business decisions, including, but not limited to, decisions with respect to the execution of contracts, settlements, disposition of assets, or the creation, appointment, or removal of officer positions require more than 50% approval of the members.

(8) Distributions in excess of cumulative earnings, classified as investing cash flows in the consolidated statements of cash flows, are calculated on an individual investment basis.

(9) Recorded in Impairments in the consolidated statements of operations.

9. EQUITY INVESTMENTS (CONTINUED)

The investment balance in Fort Union at December 31, 2017, is $3.1 million less than the Partnership's underlying equity in Fort Union's net assets due to an impairment loss recognized by the Partnership in the second quarter of 2017 for its investment in Fort Union. This investment was impaired to its estimated fair value of $8.5 million, using the income approach and Level 3 fair value inputs.
The investment balance in Rendezvous at December 31, 2017, includes $36.2 million for the purchase price allocated to the investment in Rendezvous in excess of the historic cost basis of Western Gas Resources, Inc. ("WGRI"), the entity that previously owned the interest in Rendezvous, which Anadarko acquired in August 2006. This excess balance is attributable to the difference between the fair value and book value of such gathering and treating facilities (at the time WGRI was acquired by Anadarko) and is being amortized over the remaining estimated useful life of those facilities.
The investment balance in White Cliffs at December 31, 2017, is $6.9 million less than the Partnership's underlying equity in White Cliffs' net assets, primarily due to the Partnership recording the acquisition of its initial 0.4% interest in White Cliffs at Anadarko's historic carrying value. This difference is being amortized to Equity income, net – affiliates over the remaining estimated useful life of the White Cliffs pipeline.
An impairment loss was recognized by the operator of Fort Union during both the years ended December 31, 2016 and 2015. The Partnership's 14.81% share of the impairment loss was $3.0 million and $9.5 million for the years ended December 31, 2016 and 2015, respectively, recorded in Equity income, net – affiliates in the consolidated statements of operations.
Management evaluates its equity investments for impairment whenever events or changes in circumstances indicate that the carrying value of such investments may have experienced a decline in value that is other than temporary. When evidence of loss in value has occurred, management compares the estimated fair value of the investment to the carrying value of the investment to determine whether the investment has been impaired. Management assesses the fair value of equity investments using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third-party comparable sales and discounted cash flow models. If the estimated fair value is less than the carrying value, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.
The following tables present the summarized combined financial information for the Partnership's equity investments (amounts represent 100% of investee financial information):

	Year Ended December 31,		
thousands	2017	2016	2015
Consolidated Statements of Income			
Revenues	$703,424	$687,554	$667,554
Operating income	435,735	428,454	359,899
Net income	434,749	427,511	359,443

	December 31,	
thousands	2017	2016
Consolidated Balance Sheets		
Current assets	$137,957	$118,472
Property, plant and equipment, net	2,512,214	2,626,466
Other assets	36,373	39,802
Total assets	$2,686,544	$2,784,740
Current liabilities	80,490	63,468
Non-current liabilities	7,447	6,662
Equity	2,598,607	2,714,610

Total liabilities and equity	$2,686,544	$2,784,740

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

10. COMPONENTS OF WORKING CAPITAL

A summary of accounts receivable, net is as follows:

	December 31,	
thousands	2017	2016
Trade receivables, net	$160,387	$192,808
Other receivables, net	45	30,415
Total accounts receivable, net	$160,432	$223,223

A summary of other current assets is as follows:

	December 31,	
thousands	2017	2016
Natural gas liquids inventory	$10,788	$7,126
Imbalance receivables	1,640	3,483
Prepaid insurance	2,388	2,257
Total other current assets	$14,816	$12,866

A summary of accrued liabilities is as follows:

	December 31,	
thousands	2017	2016
Accrued interest expense	$40,632	$39,826
Short-term asset retirement obligations	2,304	3,114
Short-term remediation and reclamation obligations	833	630
Income taxes payable	2,495	1,006
Other	1,635	532
Total accrued liabilities	$47,899	$45,108

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

11. ASSET RETIREMENT OBLIGATIONS

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

	Year Ended December 31,	
thousands	2017	2016
Carrying amount of asset retirement obligations at beginning of year	$ 142,407	$ 130,631
Liabilities incurred	16,153	5,515
Liabilities settled	(10,468)	(10,650)
Accretion expense	6,956	6,794
Revisions in estimated liabilities	(9,350)	10,117
Carrying amount of asset retirement obligations at end of year	$ 145,698	$ 142,407

The liabilities incurred for the year ended December 31, 2017, represented additions in asset retirement obligations primarily due to (i) capital expansions at the DJ Basin and DBM complexes and the DBJV system, (ii) the Property Exchange in March 2017 and (iii) the start-up of the DBM water systems in 2017. Revisions in estimated liabilities for the year ended December 31, 2017, were related to (i) changes in expected settlement costs and timing primarily at the Hilight system and the DJ Basin and DBM complexes, and (ii) changes in property lives primarily at the Granger, DJ Basin and DBM complexes and the Hilight and DBJV systems.
The liabilities incurred for the year ended December 31, 2016, represented additions in asset retirement obligations primarily due to capital expansions at the DJ Basin and DBM complexes and the DBJV system. Revisions in estimated liabilities for the year ended December 31, 2016, were related to (i) changes in expected settlement costs and timing primarily at the MGR assets, Granger complex and the Hilight and Springfield systems, and (ii) changes in property lives primarily at the DJ Basin and DBM complexes and the Hilight, Springfield and Haley systems.

12. DEBT AND INTEREST EXPENSE

At December 31, 2017, the Partnership's debt consisted of 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"), 3.950% Senior Notes due 2025 (the "2025 Notes"), 4.650% Senior Notes due 2026 (the "2026 Notes") and borrowings on the RCF.
The following table presents the Partnership's outstanding debt as of December 31, 2017 and 2016:

	December 31, 2017			December 31, 2016		
thousands	Principal	Carrying Value	Fair Value [1]	Principal	Carrying Value	Fair Value [1]
2021 Notes	$500,000	$495,815	$530,647	$500,000	$494,734	$536,252
2022 Notes	670,000	668,849	684,043	670,000	668,634	681,723
2018 Notes	350,000	349,684	350,631	350,000	349,188	351,531
2044 Notes	600,000	593,234	637,827	600,000	593,132	615,753
2025 Notes	500,000	491,885	500,885	500,000	490,971	492,499
2026 Notes	500,000	495,245	520,144	500,000	494,802	518,441
RCF	370,000	370,000	370,000	—	—	—
Total long-term debt	$3,490,000	$3,464,712	$3,594,177	$3,120,000	$3,091,461	$3,196,199

[1] Fair value is measured using the market approach and Level 2 inputs.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

12. DEBT AND INTEREST EXPENSE (CONTINUED)

Debt activity. The following table presents the debt activity of the Partnership for the years ended December 31, 2017 and 2016:

thousands	Carrying Value
Balance at December 31, 2015	$ 2,690,651
RCF borrowings	600,000
Issuance of 2026 Notes	500,000
Issuance of 2044 Notes	200,000
Repayments of RCF borrowings	(900,000)
Other	810
Balance at December 31, 2016	$ 3,091,461
RCF borrowings	370,000
Other	3,251
Balance at December 31, 2017	$ 3,464,712

Senior Notes. The 2018 Notes, which are due in August 2018, were classified as long-term debt on the consolidated balance sheet at December 31, 2017, as the Partnership has the ability and intent to refinance these obligations using long-term debt.

In October 2016, the Partnership issued an additional $200.0 million in aggregate principal amount of 2044 Notes at a price to the public of 102.776% of the face amount plus accrued interest from October 1, 2016 to the settlement date. These notes were offered as additional notes under the indenture governing the 2044 Notes issued in March 2014 and are treated as a single class of securities with the 2044 Notes under such indenture. Including the effects of (i) the issuance premium for the October 2016 offering of the 2044 Notes, (ii) the issuance discount for the March 2014 offering of the 2044 Notes and (iii) the underwriting discounts, the effective interest rate of the 2044 Notes is 5.530%. Proceeds (net of underwriting discount of $1.8 million and debt issuance costs and excluding accrued interest from October 1, 2016 to the settlement date) were used to repay amounts then outstanding under the RCF and for general partnership purposes, including capital expenditures.

The 2026 Notes issued in July 2016 were offered at a price to the public of 99.796% of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rate of the 2026 Notes is 4.787%. Interest is paid semi-annually on January 1 and July 1 of each year. Proceeds (net of underwriting discount of $3.1 million, original issue discount and debt issuance costs) were used to repay a portion of the amount outstanding under the RCF.

At December 31, 2017, the Partnership was in compliance with all covenants under the indentures governing its outstanding notes.

Revolving credit facility. The $1.2 billion RCF, which is expandable to a maximum of $1.5 billion, bears interest at the London Interbank Offered Rate (“LIBOR”), plus applicable margins ranging from 0.975% to 1.45%, or an alternate base rate equal to the greatest of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.50%, or (c) LIBOR plus 1.00%, in each case plus applicable margins currently ranging from zero to 0.45%, based upon the Partnership’s senior unsecured debt rating. In December 2016, the RCF was amended to extend the maturity date from February 2019 to February 2020. The Partnership is required to pay a quarterly facility fee currently ranging from 0.15% to 0.30% of the commitment amount (whether used or unused), based upon the Partnership’s senior unsecured debt rating. The facility fee rate was 0.20% at December 31, 2017 and 2016.

As of December 31, 2017, the Partnership had $370.0 million of outstanding RCF borrowings and $4.6 million in outstanding letters of credit (resulting in $825.4 million available borrowing capacity), and was in compliance with all covenants under the RCF. As of December 31, 2017 and 2016, the interest rate on the outstanding RCF borrowings was 2.87% and 2.07%, respectively. In February 2018, the RCF was amended to extend the maturity date from February 2020 to February 2023 and expand borrowing capacity to $1.5 billion.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

12. DEBT AND INTEREST EXPENSE (CONTINUED)

All notes and obligations under the RCF are recourse to the Partnership's general partner. The Partnership's general partner is indemnified by wholly owned subsidiaries of Anadarko against any claims made against the general partner for the Partnership's long-term debt and/or borrowings under the RCF.

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

	Year Ended December 31,		
thousands	2017	2016	2015
Third parties			
Long-term debt	$(142,525)	$(121,832)	$(102,058)
Amortization of debt issuance costs and commitment fees	(6,616)	(6,398)	(5,734)
Capitalized interest	6,826	5,562	8,318
Total interest expense – third parties	(142,315)	(122,668)	(99,474)
Affiliates			
Deferred purchase price obligation – Anadarko[1]	(71)	7,747	(14,398)
Total interest expense – affiliates	(71)	7,747	(14,398)
Interest expense	$(142,386)	$(114,921)	$(113,872)

[1] See Note 2 for a discussion of the Deferred purchase price obligation - Anadarko.

13. COMMITMENTS AND CONTINGENCIES

Environmental obligations. The Partnership is subject to various environmental-remediation obligations arising from federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters. As of December 31, 2017 and 2016, the consolidated balance sheets included $1.8 million and $2.2 million, respectively, of liabilities for remediation and reclamation obligations. The current portion of these amounts is included in Accrued liabilities and the long-term portion of these amounts is included in Asset retirement obligations and other. The recorded obligations do not include any anticipated insurance recoveries. The majority of payments related to these obligations are expected to be made over the next five years. Management regularly monitors the remediation and reclamation process and the liabilities recorded and believes that the amounts reflected in the Partnership's recorded environmental obligations are adequate to fund remedial actions to comply with present laws and regulations, and that the ultimate liability for these matters, if any, will not differ materially from recorded amounts nor materially affect the Partnership's overall results of operations, cash flows or financial condition. There can be no assurance, however, that current regulatory requirements will not change, or past non-compliance with environmental issues will not be discovered. See Note 10 and Note 11.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

13. COMMITMENTS AND CONTINGENCIES (CONTINUED)

Litigation and legal proceedings. In February 2017, DBJV, at the time a 50/50 joint venture between a third party and the Partnership, initiated an arbitration against SWEPI LP (“SWEPI”) for breach of a 2007 gas gathering agreement between it and DBJV (the “GGA”). Specifically, DBJV seeks to collect approximately $190.0 million in gathering fees under the GGA for the period January 1, 2016 to July 1, 2017. SWEPI disputes DBJV’s calculation of the cost of service based rate and filed a counterclaim for alleged unpaid revenue associated with its condensate and for alleged overpayment of fees under the GGA for the years 2013 through 2016. Before the arbitration, SWEPI claimed that it is owed approximately $18.0 million in connection with these counterclaims. The final arbitration hearing will begin April 30, 2018, and the Partnership expects to receive a decision by the end of the third quarter in 2018. Under the terms of the Property Exchange, the Partnership’s former joint venture partner in DBJV will owe 50% of any amounts to be paid, and have a right to 50% of any amounts received, by the Partnership as a result of this arbitration proceeding. Pursuant to an agreement between the parties, if the arbitrators determine that DBJV is owed an amount of money by SWEPI for underpaid gathering fees, that amount will be paid out over five years as a supplemental gathering fee under the currently effective gas gathering agreement between the parties. Any other amounts owed by either party will be paid in cash within ninety days of the conclusion of the arbitration. The Partnership intends to vigorously prosecute its claims and vigorously defend the counterclaims asserted by SWEPI. Management does not believe the outcome of this proceeding will have a materially unfavorable effect on the Partnership’s financial condition, results of operation or cash flows.
In addition, from time to time, the Partnership is involved in legal, tax, regulatory and other proceedings in various forums regarding performance, contracts and other matters that arise in the ordinary course of business. Management is not aware of any such proceeding the final disposition of which could have a material adverse effect on the Partnership’s financial condition, results of operations or cash flows.

Other commitments. The Partnership has short-term payment obligations, or commitments, related to its capital spending programs, as well as those of its unconsolidated affiliates, the majority of which is expected to be paid in the next twelve months. These commitments relate primarily to expansion projects at the DBJV system and the DJ Basin and DBM complexes.

Lease commitments. Anadarko, on behalf of the Partnership, has entered into lease arrangements for corporate offices, shared field offices, a warehouse and equipment supporting the Partnership’s operations, for which Anadarko charges the Partnership rent. The leases for the corporate offices and shared field offices extend through 2028 and 2033, respectively, and the lease for the warehouse expired in February 2017. Rent expense charged to the Partnership associated with these lease arrangements was $42.5 million, $35.9 million and $34.1 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Operating leases. The amounts in the table below represent existing contractual operating lease obligations as of December 31, 2017, that may be assigned or otherwise charged to the Partnership pursuant to the reimbursement provisions of the omnibus agreement:

thousands	Operating Leases
2018	$ 8,402
2019	7,506
2020	1,615
2021	460
2022	467
Thereafter	2,021

Total	$ 20,471

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WESTERN GAS PARTNERS, LP
SUPPLEMENTAL QUARTERLY INFORMATION
(UNAUDITED)

The following table presents a summary of the Partnership's operating results by quarter for the years ended December 31, 2017 and 2016. The Partnership's operating results reflect the operations of the Partnership assets (as defined in Note 1—Summary of Significant Accounting Policies) from the dates of common control, unless otherwise noted. See Note 1—Summary of Significant Accounting Policies and Note 2—Acquisitions and Divestitures.

thousands except per-unit amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2017				
Total revenues and other	$516,193	$525,450	$574,695	$632,018
Equity income, net – affiliates	19,461	21,728	21,519	22,486
Gain (loss) on divestiture and other, net	119,487	15,458	72	(2,629)
Proceeds from business interruption insurance claims	5,767	24,115	—	—
Operating income (loss)	138,392	207,608	179,456	181,815
Net income (loss)	103,991	175,497	147,913	150,817
Net income (loss) attributable to Western Gas Partners, LP	101,889	173,451	143,506	148,637
Net income (loss) per common unit – basic and diluted[1]	0.01	0.49	0.38	0.39
2016				
Total revenues and other	$383,141	$428,664	$481,645	$510,820
Equity income, net – affiliates	16,814	19,693	20,294	21,916
Gain (loss) on divestiture and other, net	(632)	(1,907)	(6,230)	(5,872)
Proceeds from business interruption insurance claims	—	2,603	13,667	—
Operating income (loss)	153,403	176,362	197,288	181,155
Net income (loss)	119,083	167,325	170,426	145,460
Net income (loss) attributable to Western Gas Partners, LP	116,060	164,521	167,746	143,004
Net income (loss) per common unit – basic and diluted[1]	0.31	0.55	0.54	0.35

(1) Represents net income (loss) earned on and subsequent to the date of acquisition of the Partnership assets.

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure
None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. The Chief Executive Officer and Chief Financial Officer of the Partnership's general partner (for purposes of this Item 9A, "Management") performed an evaluation of the Partnership's disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act. Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and to ensure that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, Management concluded that the Partnership's disclosure controls and procedures were effective as of December 31, 2017.

Management's Annual Report on Internal Control Over Financial Reporting. See Management's Assessment of Internal Control Over Financial Reporting under Item 8 of this Form 10-K.

Attestation Report of the Registered Public Accounting Firm. See Report of Independent Registered Public Accounting Firm under Item 8 of this Form 10-K.

Changes in Internal Control Over Financial Reporting. During the quarter ended December 31, 2017, we implemented changes to internal control over financial reporting related to the accounting for revenue as a result of the adoption of the revenue recognition standard effective January 1, 2018. The modified and new controls have been designed to address risks associated with recognizing revenue under the new standard, including modifications to accounting policies and contract review controls. There were no other changes in our internal control over financial reporting during the quarter ended December 31, 2017, that have materially affected, or are reasonably likely to materially affect, the Partnership's internal control over financial reporting.

Item 9B. Other Information

On February 15, 2018, the Partnership entered into a five-year senior unsecured revolving credit agreement (the "2018 RCF"), amending and restating the RCF, which was originally entered into in February 2014 and had an outstanding balance of $630.0 million, with $4.6 million in outstanding letters of credit, immediately prior to closing on the 2018 RCF. The aggregate initial commitments of the 2018 RCF lenders are $1.5 billion, and they are expandable to a maximum of $2.0 billion. The 2018 RCF matures on February 15, 2023, with options to extend maturity by up to two additional one year increments, and bears interest at LIBOR, plus applicable margins ranging from 1.00% to 1.50%, or an alternate base rate equal to the greatest of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.50%, or (c) LIBOR plus 1.00%, in each case plus applicable margins currently ranging from zero to 0.50%, based upon the Partnership's senior unsecured debt rating. The Partnership is required to pay a quarterly facility fee ranging from 0.125% to 0.250% of the commitment amount (whether used or unused), also based upon its senior unsecured debt rating. The 2018 RCF contains covenants and customary events of default that are substantially similar to the RCF. As of February 16, 2018, there was $630.0 million outstanding on the 2018 RCF (with $4.6 million in outstanding letters of credit), which was drawn to repay amounts that were outstanding under the RCF. The above summary of the 2018 RCF is qualified in its entirety by reference to the 2018 RCF, a copy of which is filed as Exhibit 10.21 hereto.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

Management of Western Gas Partners, LP

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

Our Board of Directors has eight members, four of whom are independent as defined under the independence standards established by the NYSE and the Exchange Act. The NYSE does not require a listed limited partnership, such as us, to have a majority of independent directors on the Board of Directors or to establish a compensation committee or a nominating committee. Our Board of Directors has affirmatively determined that Messrs. Steven D. Arnold, Milton Carroll, James R. Crane and David J. Tudor are independent as described in the rules of the NYSE and the Exchange Act. With respect to Mr. Crane, the Board specifically considered the transactions described under Part III, Item 13 of this Form 10-K, as well as payments by Anadarko to a company affiliated with Mr. Crane and a contribution made by Anadarko to a charitable institution affiliated with Mr. Crane. The Board determined that such transactions do not impact Mr. Crane’s independence. With respect to Mr. Arnold, the Board specifically considered that Mr. Arnold holds 4,900 shares of Anadarko stock. The Board determined that the ownership of these shares does not impact Mr. Arnold’s independence. With respect to Mr. Carroll, the Board specifically considered that he is the Executive Chairman of CenterPoint Energy, Inc. (“CenterPoint”), with which Anadarko entered into approximately $26.1 million in gas purchase and sale transactions during 2017. These transactions represent an immaterial amount of both Anadarko and CenterPoint revenues and were on standard terms, negotiated without any involvement from Mr. Carroll. Accordingly, the Board determined that such transactions do not impact Mr. Carroll’s independence.

The executive officers of our general partner manage and conduct our day-to-day operations. The executive officers of our general partner allocate their time between managing our business and affairs and the business and affairs of Anadarko, and may face a conflict regarding the allocation of their time. We expect that the amount of time the executive officers of our general partner devote to our business may increase or decrease in future periods as our business continues to develop. The executive officers of our general partner and other Anadarko employees operate our business and provide us with general and administrative services pursuant to the omnibus agreement and the services and secondment agreement described under Part III, Item 13 of this Form 10-K. We reimburse Anadarko for certain allocated expenses of operational personnel who perform services for our benefit, and for certain direct expenses.

Board Leadership Structure

Through its ownership and control of WGP GP, Anadarko controls our general partner and, within the limitations of our partnership agreement and applicable SEC and NYSE rules and regulations, also exercises broad discretion in establishing the governance provisions of our general partner’s limited liability company agreement. Accordingly, our general partner’s board structure is established by Anadarko.

Although our general partner’s current board structure has separated the roles of Chairman and Chief Executive Officer (“CEO”), our general partner’s limited liability company agreement and Corporate Governance Guidelines permit the roles of Chairman and CEO to be combined. Anadarko may in the future combine those roles at its discretion.

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Directors and Executive Officers

The biography of each director below contains information regarding that person's service as a director, business experience, director positions held currently or at any time during the last five years, and involvement in certain legal or administrative proceedings, if applicable, and the experiences, qualifications, attributes or skills that caused our general partner and its Board of Directors to determine that the person should serve as a director of our general partner. In light of our strategic relationship with our sponsor, Anadarko, our general partner considers service as an Anadarko executive to be a meaningful qualification for service as a non-independent director of our general partner. The following table sets forth certain information with respect to the directors and executive officers of our general partner as of February 12, 2018. Directors are appointed for a term of one year.

Name	Age	Position with Western Gas Holdings, LLC
Robert G. Gwin	54	Chairman of the Board
Donald R. Sinclair	60	President, Chief Executive Officer and Director (through February 12, 2017)
Benjamin M. Fink	47	President, Chief Executive Officer and Director
Jaime R. Casas	47	Senior Vice President, Chief Financial Officer and Treasurer
Craig W. Collins	45	Senior Vice President and Chief Operating Officer
Philip H. Peacock	46	Senior Vice President, General Counsel and Corporate Secretary
Steven D. Arnold	57	Director
Daniel E. Brown	42	Director
Milton Carroll	67	Director
James R. Crane	64	Director
Darrell E. Hollek	60	Director (through December 31, 2017)
Robert K. Reeves	60	Director
David J. Tudor	58	Director

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

Robert G. Gwin Age: 54 Houston, Texas Director since: August 2007 Not Independent Officer from: August 2007 to January 2010	Biography/Qualifications Robert G. Gwin has served as a director of our general partner since 2007 and has served as Chairman of the Board of our general partner since 2009. He also served as Chief Executive Officer of our general partner from 2007 to 2010 and as President from 2007 to 2009. Mr. Gwin has also served as Chairman of the Board of WGP GP since September 2012. He was named Executive Vice President, Finance and Chief Financial Officer of Anadarko in May 2013 and previously served as Senior Vice President, Finance and Chief Financial Officer beginning in 2009. Mr. Gwin has also served as Chairman of the Board of LyondellBasell Industries N.V. since August 2013 and as a director since 2011.
Donald R. Sinclair Age: 60 Houston, Texas Director from:	Biography/Qualifications From 2010 until his retirement in February 2017, Mr. Sinclair served as President, Chief Executive Officer and a director of our general partner and from 2009 to 2010, he served as President and a director. From September 2012 to February 2017, Mr. Sinclair also served as the President and Chief Executive Officer and as a director of WGP GP. From May 2013 to February 2017, he served as Senior

October 2009 to February 2017 Not Independent Officer from: October 2009 to February 2017	Vice President of Anadarko, prior to which he served as a Vice President of Anadarko beginning in 2010. Prior to joining Anadarko and becoming President and a director of our general partner, Mr. Sinclair was a founding partner and served as President of Ceritas Energy, LLC, a midstream energy company headquartered in Houston with operations in Texas, Wyoming and Utah from 2003 to 2009. Mr. Sinclair has worked in the oil and gas industry for over 35 years, with a focus on marketing and trading and the midstream sector.

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Benjamin M. Fink Age: 47 Houston, Texas Director since: February 2017 Not Independent Officer since: 2009	Biography/Qualifications Benjamin M. Fink has served as President and Chief Executive Officer of our general partner and WGP GP since May 2017 and as a director since February 2017. He previously served as President, Chief Executive Officer, Chief Financial Officer and Treasurer of our general partner and WGP GP from February 2017 to May 2017, and as Senior Vice President and Chief Financial Officer of our general partner from 2009 to February 2017 and of WGP GP from September 2012 to February 2017. Mr. Fink currently serves as a Senior Vice President at Anadarko, having joined the company in 2007. From 2001 until 2006, he held executive management positions at Prosoft Learning Corporation, including serving as its President and Chief Executive Officer from 2004 until that company's sale in 2006. From 2000 to 2001 he co-founded and served as Chief Operating Officer and Chief Financial Officer of Meta4 Group Limited, an online direct marketer based in Hong Kong and Tokyo. Previously, he held positions of increasing responsibility at Prudential Capital Group and Prudential Asset Management Asia, where he focused on the negotiation, structuring and execution of private debt and equity investments.
Jaime R. Casas Age: 47 Houston, Texas Officer since: May 2017	Biography/Qualifications Jaime R. Casas has served as Senior Vice President, Chief Financial Officer and Treasurer of our general partner and of WGP GP since May 2017. Mr. Casas also has served as a Vice President, Finance of Anadarko since May 2017. Prior to joining the Partnership and WGP, Mr. Casas served as Senior Vice President and Chief Financial Officer of Clayton Williams Energy, Inc. from October 2016 until the company's sale in April 2017. Previously, he served as Vice President and Chief Financial Officer of the general partner of LRR Energy, L.P., a publicly traded exploration and production master limited partnership, from 2011 to October 2015, and as Vice President and Chief Financial Officer of Laredo Energy, a privately held oil and gas company, from 2009 to 2011. Prior to joining Laredo Energy, Mr. Casas worked for over a decade in various positions and industry groups in the investment banking divisions at Donaldson, Lufkin & Jenrette and Credit Suisse. Mr. Casas began his career in 1993 as a management information consultant with Andersen Consulting.
Craig W. Collins Age: 45 Houston, Texas Officer since: February 2017	Biography/Qualifications Craig W. Collins has served as Senior Vice President and Chief Operating Officer of our general partner and WGP GP since February 2017. Mr. Collins was named Vice President – Midstream for Anadarko in February 2017, and previously served as Director, Midstream Engineering for Anadarko from July 2016 to February 2017, during which time he was responsible for the engineering and construction of midstream infrastructure for Anadarko and the Partnership. He joined the Anadarko midstream organization in November 2010, where he led commercial development activities in the Eagleford shale, and was promoted to General Manager in June 2013, with commercial responsibilities for midstream assets located in Texas, New Mexico, Kansas, Louisiana, and Pennsylvania. Since joining Anadarko in 2003, Mr. Collins has also held positions of increasing responsibility in Treasury and Corporate Development.
Philip H. Peacock Age: 46 Houston, Texas Officer since:	Biography/Qualifications Philip H. Peacock has served as Senior Vice President, General Counsel and Corporate Secretary of our general partner and WGP GP since February 2017, and served as Vice President, General Counsel and Corporate Secretary of our general partner from August 2012 until February 2017. Mr. Peacock served as Vice President, General Counsel and Corporate Secretary of WGP GP from September 2012 until February 2017. Prior to joining the Partnership, Mr. Peacock was a partner practicing corporate and

August 2012	securities law at the law firm of Andrews Kurth LLP, which he joined in 2003. He is licensed to practice law in the state of Texas.

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Steven D. Arnold Age: 57 Houston, Texas Director since: February 2014 Independent	Biography/Qualifications Steven D. Arnold has served as a director of our general partner and as a member of the Special Committee and Audit Committee of the Board of Directors since February 2014. Mr. Arnold served on the Board of Directors of the general partner of Spectra Energy Partners, LP from 2007 to December 2013, during which time he served on that board’s Audit Committee and Conflicts Committee. He served as Chairman of each of those committees at separate times during his board membership. Mr. Arnold is engaged in private investment management and consulting services in Houston, Texas through 3 Lights Management Co., serving as its President since inception in 2000. Mr. Arnold has over ten years of institutional investment management experience with Prudential Financial, Inc. Mr. Arnold brings strong risk assessment and strategic expertise to the board.
Daniel E. Brown Age: 42 Houston, Texas Director since: November 2017 Not Independent	Biography/Qualifications Daniel E. Brown has served as a director of our general partner and of WGP GP since November 2017. Mr. Brown has served as Executive Vice President, U.S. Onshore Operations, with responsibility for Anadarko’s upstream and midstream activity in Colorado, Texas, Utah and Wyoming since October 2017. He previously served as Executive Vice President, International and Deepwater Operations from May to October 2017, Senior Vice President, International and Deepwater Operations from August 2016 to May 2017, and Vice President, Operations for Anadarko’s Southern and Appalachia Region from August 2013 to August 2016. Mr. Brown has nearly 20 years of experience in the oil and natural gas industry, beginning his career in 1998 with Kerr-McGee Corporation. He has since held a variety of positions within Anadarko, including Vice President, Corporate Planning, General Manager of the Maverick Basin and Anadarko’s Freestone/Chalk area (U.S. onshore), Business Advisor for Planning and Reserves Administration in the Gulf of Mexico, and in engineering positions in both the U.S. onshore and the Gulf of Mexico.
Milton Carroll Age: 67 Houston, Texas Director since: 2008 Independent	Biography/Qualifications Milton Carroll has served as a director of our general partner and as Chairman of the Special Committee of the Board of Directors since 2008. Mr. Carroll currently serves as Executive Chairman of Houston-based CenterPoint Energy, Inc., where he has been a director since 1992. He also serves as Chairman of Health Care Services Corporation (a Chicago-based company operating through its Blue Cross and Blue Shield divisions in Illinois, Texas, Oklahoma, New Mexico, and Montana) and as a director of Halliburton Company, where he serves as a member of the Compensation Committee and the Nominating and Corporate Governance Committee. From 2010 to July 2016, Mr. Carroll served as a director of LyondellBasell Industries N.V., where he served as a member of the Nominating and Governance Committee and the Compensation Committee, and from 2011 to January 2014, he served as a director of the general partner of LRR Energy, L.P. Mr. Carroll also served as a director of EGL, Inc. from 2003 until 2007 and as a director of the general partner of DCP Midstream Partners, LP from 2005 to 2006.
James R. Crane Age: 64 Houston, Texas Director since:	Biography/Qualifications James R. Crane has served as a director of our general partner and as a member of the Special Committee and Audit Committee of the Board of Directors since 2008. In 2011, Mr. Crane became the principal owner and Chairman of the Houston Astros Baseball Club. Mr. Crane is also the Chairman and Chief Executive Officer of Crane Capital Group Inc., an investment management company he founded. Crane Capital Group currently invests in transportation, power distribution, real estate and asset

April 2008 Independent	management. Its holdings include Crane Worldwide Logistics, a premier global provider of customized transportation and logistics services with 54 offices in 20 countries. Prior to founding Crane Capital Group Inc., he was founder, Chairman and Chief Executive Officer of EGL, Inc., a global transportation, supply chain management and information services company, from 1984 until its sale in 2007. Mr. Crane currently serves as a director of Nabors Industries Ltd., an international drilling contractor and well-services provider. From 2010 to February 2012, he served as a director of Fort Dearborn Life Insurance Company, a subsidiary of Health Care Service Corporation, and from 1999 to 2007 he served as a director of HCC Insurance Holdings, Inc.

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Darrell E. Hollek Age: 60 Houston, Texas Director from: May 2015 to December 2017 Not Independent	Biography/Qualifications From May 2015 until his retirement in December 2017, Darrell E. Hollek served as a director of our general partner and as a director of WGP GP from May 2015 until November 2017. Mr. Hollek served as Executive Vice President, Operations of Anadarko from August 2016 to May 2017. He served as Executive Vice President, U.S. Onshore Exploration and Production of Anadarko from April 2015 to August 2016, and served as Senior Vice President, Operations (Deepwater Americas) of Anadarko from May 2013 to April 2015. Prior to these positions, he served as Vice President, Operations of Anadarko since 2007. Mr. Hollek joined Anadarko upon the acquisition of Kerr-McGee Corporation in 2006. He has held positions of increasing responsibility with Anadarko and Kerr-McGee Corporation, where he began his career, including management roles in the Gulf of Mexico, U.S. Onshore and Environmental, Health, Safety and Regulatory.
Robert K. Reeves Age: 60 Houston, Texas Director since: 2007 Not Independent	Biography/Qualifications Robert K. Reeves has served as a director of our general partner since 2007 and as a director of WGP GP since September 2012. Mr. Reeves was named Executive Vice President, Law and Chief Administrative Officer of Anadarko in September 2015 and previously served as Executive Vice President, General Counsel and Chief Administrative Officer since May 2013 and as Senior Vice President, General Counsel and Chief Administrative Officer since 2007. He also served as a director of Key Energy Services, Inc., a publicly traded oil field services company, from 2007 to December 2016. Prior to joining Anadarko, he served as Executive Vice President, Administration and General Counsel of North Sea New Ventures from 2003 to 2004 and as Executive Vice President, General Counsel and Secretary of Ocean Energy, Inc. and its predecessor companies from 1997 to 2003.
David J. Tudor Age: 58 Houston, Texas Director since: 2008 Independent	Biography/Qualifications David J. Tudor has served as a director of our general partner and as Chairman of the Audit Committee of the Board of Directors since 2008, and previously served as a member of the Special Committee of the Board of Directors from 2008 to December 2012. Mr. Tudor has served as a director of WGP GP and as Chairman of the Audit Committee of its Board of Directors since December 2012. Since May 2016, Mr. Tudor has served as Chief Executive Officer and General Manager of Associated Electric Cooperative Inc., a member-owned, member-governed wholesale power provider serving Missouri, Iowa and Oklahoma. From May 2013 to May 2016, Mr. Tudor served as President and Chief Executive Officer of Champion Energy Services, a retail electric provider. From 1999 through 2013, Mr. Tudor was the President and Chief Executive Officer of ACES, an Indianapolis-based commodity risk management company owned by 21 generation and transmission cooperatives throughout the United States. Prior to joining ACES, Mr. Tudor was the Executive Vice President & Chief Operating Officer of PG&E Energy Trading, where he managed commercial operations in the United States and Canada.

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Section 16(a) Beneficial Ownership Reporting Compliance

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

To our knowledge, based solely on a review of the copies of such reports furnished to us and written representations that no other reports were required, we believe that all reporting obligations of our general partner's officers, directors and greater-than-10-percent unitholders under Section 16(a) were satisfied during the year ended December 31, 2017.

Reimbursement of Expenses of Our General Partner and Its Affiliates

Our general partner does not receive any management fee or other compensation for its management of our Partnership under the omnibus agreement, the services and secondment agreement or otherwise. Under our partnership and omnibus agreements, we reimburse Anadarko for general and administrative expenses allocated to us, as determined by Anadarko in its reasonable discretion. Read Part III, Item 13 of this Form 10-K for additional information regarding these agreements.

Board Committees

The Board of Directors has two standing committees: the Audit Committee and the Special Committee.

Audit Committee

The Audit Committee is comprised of three independent directors, Messrs. Tudor (Chairman), Arnold and Crane, each of whom is able to understand fundamental financial statements and at least one of whom has past experience in accounting or related financial management experience. The Board has determined that each member of the Audit Committee is independent under the NYSE listing standards and the Exchange Act. In making the independence determination, the Board considered the requirements of the NYSE and our Code of Business Conduct and Ethics. The Audit Committee held four meetings in 2017.

Mr. Tudor has been designated by the Board of Directors as the "Audit Committee financial expert" meeting the requirements promulgated by the SEC based upon his education and employment experience as more fully detailed in Mr. Tudor's biography set forth above.

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

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Special Committee

The Special Committee is comprised of three independent directors, Messrs. Carroll (Chairman), Arnold, and Crane. The Special Committee reviews specific matters that the Board believes may involve conflicts of interest (including certain transactions with Anadarko). The Special Committee will determine, as set forth in the partnership agreement, if the resolution of a conflict of interest submitted to it is fair and reasonable to us. The members of the Special Committee are not officers or employees of our general partner or directors, officers, or employees of its affiliates, including Anadarko. Our partnership agreement provides that any matters approved in good faith by the Special Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. The Special Committee held two meetings in 2017.

Meeting of Non-Management Directors and Communications with Directors

At each quarterly meeting of our Board of Directors, all of our independent directors meet in an executive session without management participation or participation by non-independent directors. Mr. Carroll, the Chairman of the Special Committee, presides over these executive sessions.
The Board of Directors welcomes questions or comments about the Partnership and its operations. Unitholders or interested parties may contact the Board of Directors, including any individual director, at boardofdirectors@westerngas.com or at the following address and fax number: Name of the Director(s), c/o Corporate Secretary, Western Gas Partners, LP, 1201 Lake Robbins Drive, The Woodlands, Texas 77380, (832) 636-6001.

Code of Ethics, Corporate Governance Guidelines and Board Committee Charters

Our general partner has adopted a Code of Ethics for CEO and Senior Financial Officers (the “Code of Ethics”), which applies to our general partner’s Chief Executive Officer, Chief Financial Officer, principal accounting officer, Controller and all other senior financial and accounting officers of our general partner. If the general partner amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, we will disclose the information on our website. Our general partner has also adopted Corporate Governance Guidelines that outline the important policies and practices regarding our governance and a Code of Business Conduct and Ethics applicable to all employees of Anadarko or affiliates of Anadarko who perform services for us and our general partner.
We make available free of charge, within the “Governance” section of our website at www.westerngas.com, and in print to any unitholder who so requests, our Code of Ethics, Corporate Governance Guidelines, Code of Business Conduct and Ethics, Audit Committee charter and Special Committee charter. Requests for print copies may be directed to investors@westerngas.com or to: Investor Relations, Western Gas Partners LP, 1201 Lake Robbins Drive, The Woodlands, Texas 77380, or telephone (832) 636-6000. The information contained on, or connected to, our website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

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Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

Overview

We do not directly employ any of the persons responsible for managing our business, and our Board of Directors does not have a compensation committee. The compensation of Anadarko's employees that perform services on our behalf, including our executive officers, is approved by Anadarko's management. Our reimbursement to Anadarko for the compensation of executive officers is governed by the omnibus agreement. Under our partnership and omnibus agreements, we reimburse general and administrative expenses as determined by Anadarko in its reasonable discretion. Read the caption Omnibus Agreement under Part III, Item 13 of this Form 10-K.

Our "named executive officers" for 2017 were Donald R. Sinclair (the principal executive officer through February 12, 2017), Benjamin M. Fink (the principal executive officer effective February 13, 2017; the principal financial officer through May 21, 2017), Jaime R. Casas (the principal financial officer and principal accounting officer effective May 22, 2017), Craig W. Collins (the principal operating officer effective February 13, 2017) and Philip H. Peacock (the senior vice president, general counsel and corporate secretary). Compensation paid or awarded by us in 2017 with respect to the named executive officers reflects only the portion of compensation expense that is allocated to us pursuant to Anadarko's allocation methodology, as described below, and subject to the terms of the omnibus agreement. Anadarko has the ultimate decision-making authority with respect to the total compensation of the named executive officers and, subject to the terms of the omnibus agreement, the portion of such compensation we reimburse pursuant to Anadarko's allocation methodology. Generally, once Anadarko has established the aggregate amount to be paid or awarded to the named executive officers with respect to each element of compensation for services rendered to both our general partner and Anadarko, such aggregate amount is multiplied by an allocation percentage for each named executive officer. Each allocation percentage is established based on a periodic, good-faith estimate made by each named executive officer and is subject to review by the Chairman of our Board of Directors. The resulting amount (other than with respect to certain long-term incentive plan awards) is the amount reimbursed to Anadarko by us pursuant to the terms of the omnibus agreement and appears in the Summary Compensation Table below. Notwithstanding the foregoing, perquisites are not currently allocated to us, and reimbursement of bonus amounts under the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table are capped consistent with the methodology set forth in the services and secondment agreement for all employees whose compensation is allocated to us.

The following table presents the estimated percentage of time ("time allocation") that the general partner's named executive officers devoted to the Partnership during the year ended December 31, 2017, which percentage represents the time devoted to the business of the Partnership relative to time devoted to the businesses of the Partnership and Anadarko in the aggregate:

Named Executive Officers of Our General Partner	Time Allocated	Anadarko Corporate Officer
Benjamin M. Fink	90.0%	Yes
Jaime R. Casas	90.0%	Yes
Craig W. Collins	50.0%	Yes
Philip H. Peacock	50.0%	Yes
Donald R. Sinclair	50.0%	No

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Our named executive officers are compensated by Anadarko in a manner that is generally consistent with the objectives and philosophies used to develop the compensation packages for Anadarko's named executive officers, as described in the Anadarko proxy statement. The following discussion relating to compensation paid by Anadarko is based on information provided to us by Anadarko and does not purport to be a complete discussion and analysis of Anadarko's executive compensation philosophy and practices. For a more complete analysis of the compensation programs and philosophies used at Anadarko, read Compensation Discussion and Analysis contained within Anadarko's proxy statement, which is expected to be filed with the SEC no later than April 5, 2018. The elements of compensation discussed below (and Anadarko's decisions with respect to the levels of such compensation) are not subject to approvals by the WES Board of Directors or WGP Board of Directors, as applicable, including the Audit or Special Committees thereof.

Elements of Compensation

The primary elements of Anadarko's compensation program are a combination of annual cash and long-term equity-based compensation. For 2017, the principal elements of compensation for the named executive officers were as follows:

- base salary;
- annual cash incentives;
- equity-based compensation, which includes equity-based compensation under Anadarko's 2012 Omnibus Incentive Compensation Plan (the "Omnibus Plan"); and
- certain other Anadarko benefits that are provided on the same basis to other eligible Anadarko employees, including welfare and retirement benefits, severance benefits and change of control benefits, plus other benefits.

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

Annual cash incentives (bonuses). Anadarko will make annual cash awards to our named executive officers in 2018 for their performance during the year ended December 31, 2017, under the 2017 Anadarko annual incentive program ("AIP"), which is administered under the Omnibus Plan. Annual cash incentive awards are used by Anadarko to motivate its executives and employees, reward them for the achievement of Anadarko objectives aligned with value creation, and/or recognize individual contributions to Anadarko's performance. The AIP puts a portion of an executive's compensation at risk by linking potential annual compensation to Anadarko's achievement of specific operational, financial and safety performance metrics during the year. The AIP bonuses paid to our named executive officers are determined by Anadarko's management.
The portion of any annual cash awards allocable to us is based on Anadarko's methodology used for allocating general and administrative expenses, subject to the limitations established in the omnibus agreement. Anadarko's general policy is to pay these awards during the first quarter of each calendar year for the prior year's performance.

Long-term incentive awards under the Omnibus Plan. Anadarko periodically makes equity-based awards under the Omnibus Plan to align the interests of its executive officers and employees with those of Anadarko stockholders by emphasizing the long-term growth in Anadarko's value. For 2017, the annual equity awards generally consisted of a combination of (1) performance units, (2) stock options, and (3) time-based restricted stock units or shares of restricted stock. This award structure is intended to provide a combination of equity-based vehicles that is performance-based in absolute and relative terms, while also encouraging retention. The costs allocated to us for the named executive officers' compensation includes an allocation of expense associated with a portion of these awards in accordance with the allocation mechanisms in the omnibus agreement.

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

- retirement benefits to match competitive practices in Anadarko's industry, including participation in Anadarko's employee savings plan, savings restoration plan, retirement plan and retirement restoration plan;

- severance benefits under the Anadarko Officer Severance Plan;

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

- director and officer indemnification agreements;

- a limited number of perquisites, including financial counseling, tax preparation and estate planning, an executive physical program, management life insurance, voluntary participation in the Deferred Compensation Plan, and personal excess liability insurance; and

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

For a more detailed summary of Anadarko's executive compensation program and the benefits provided thereunder, read Compensation Discussion and Analysis contained within Anadarko's proxy statement for its annual meeting of stockholders, which is expected to be filed with the SEC no later than April 5, 2018.

Role of Executive Officers in Executive Compensation

Anadarko's management determines a significant part of the compensation for each of our named executive officers. The Board of Directors determines compensation for the independent, non-management directors of our general partner's Board of Directors, as well as any grants made under the WES LTIP. None of our named executive officers provides compensation recommendations to the Anadarko Compensation and Benefits Committee or Anadarko's management team regarding compensation (other than recommendations with respect to employees that report directly to them).

Compensation Mix

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

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EXECUTIVE COMPENSATION

As noted above, we do not directly employ any of the persons responsible for managing or operating our business and we have no compensation committee. Instead, we are managed by our general partner, the executive officers of which are employees of Anadarko. Our reimbursement for the compensation of executive officers is governed by the omnibus agreement and the services and secondment agreement described in the caption Agreements with Anadarko—Services and Secondment Agreement under Part III, Item 13 of this Form 10-K.

Summary Compensation Table

The following table summarizes the compensation amounts expensed by us for our named executive officers for the years ended December 31, 2017, 2016 and 2015, as applicable. Except as specifically noted, the amounts included in the table below reflect the portion of the expense allocated to us by Anadarko. For a discussion of the allocation percentages in effect for 2017, see the Overview section, above.

Name and Principal Position	Year	Salary ($) (1)	Bonus ($)	Stock Awards ($) (2)	Option Awards ($) (3)	Non-Equity Incentive Plan Compensation ($) (4)	All Other Compensation ($) (5)	Total ($)
Benjamin M. Fink	2017	415,385	—	2,062,764	1,101,952	325,122	138,498	4,043,721
President and	2016	332,135	—	1,634,281	401,340	259,066	108,526	2,735,348
Chief Executive Officer	2015	341,135	—	672,651	364,951	266,085	102,170	1,746,992
Jaime R. Casas	2017	208,731	—	1,257,309	904,934	135,675	71,607	2,578,256
Senior Vice President, Chief	2016	—	—	—	—	—	—	—
Financial Officer and Treasurer	2015	—	—	—	—	—	—	—
Craig W. Collins	2017	146,827	—	1,029,025	279,272	91,209	49,090	1,595,423
Senior Vice President and	2016	—	—	—	—	—	—	—
Chief Operating Officer	2015	—	—	—	—	—	—	—
Philip H. Peacock	2017	150,082	—	906,771	218,869	88,894	50,098	1,414,714
Senior Vice President, General Counsel	2016	129,938	—	100,020	—	62,370	42,427	334,755
and Corporate Secretary	2015	134,935	—	85,010	—	64,769	40,413	325,127
Donald R. Sinclair	2017	40,385	—	—	—	—	12,978	53,363
Former President and	2016	356,971	—	1,875,920	615,378	342,692	116,869	3,307,830
Chief Executive Officer	2015	350,481	—	828,646	449,573	336,462	104,969	2,070,131

(1) The amounts in this column reflect the base salary compensation allocated to us by Anadarko for the years ended December 31, 2017, 2016 and 2015. Mr. Sinclair's amount reflects base salary compensation earned and allocated through February 12, 2017. Mr. Casas' amount reflects base salary compensation earned and allocated since joining the Partnership on May 22, 2017.

(2) The amounts in this column reflect the expected allocation to us of the grant date fair value, computed in accordance with FASB ASC Topic 718 (without respect to the risk of forfeitures), for non-option stock awards granted pursuant to the 2012 Anadarko Omnibus Incentive Compensation Plans and include unvested amounts. For a discussion of valuation assumptions for the awards under the 2012 Anadarko Omnibus Incentive Compensation Plans, see Note 22—Share-Based Compensation in the Notes to Consolidated Financial Statements included under Part II, Item 8 of Anadarko's Form 10-K for the year ended December 31, 2017 (which is not, and shall not be deemed to be, incorporated by reference herein). For information regarding the non-option stock awards granted to the named executives in 2017, see the Grants of Plan-Based Awards Table. The amounts in this column also reflect the allocation of Anadarko performance unit awards, where such gross amounts are subject to market conditions

and have been valued based on the probable outcome of the market conditions as of the grant date.

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(3) The amounts in this column reflect the expected allocation to us of the grant date fair value, computed in accordance with FASB ASC Topic 718 (without respect to the risk of forfeitures), for option awards granted pursuant to the 2012 Anadarko Omnibus Incentive Compensation Plans. See note (2) above for valuation assumptions. For information regarding the option awards granted to the named executives in 2017, see the Grants of Plan-Based Awards Table.

(4) The amounts in this column reflect the compensation under the Anadarko annual incentive program expected to be allocated to us for the year ended December 31, 2017, and allocated to us for the years ended December 31, 2016 and 2015. Given the timing of when payments are to be made in 2018, the 2017 amounts represent payments which were earned in 2017 and are expected to be paid in early 2018, with an assumed at-target payout, which may not be indicative of the payout our named executive officers will actually receive. The 2016 amounts represent payments which were earned in 2016 and paid in early 2017 and the 2015 amounts represent the payments which were earned in 2015 and paid in early 2016. For an explanation of the 2017 annual incentive plan awards, read Compensation Discussion and Analysis – Analysis of 2017 Compensation Actions – Performance-Based Annual Cash Incentives (Bonuses), contained within Anadarko's proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 5, 2018.

(5) The amounts in this column reflect the compensation expenses related to Anadarko's retirement and savings plans that were allocated to us for the years ended December 31, 2017, 2016 and 2015. Mr. Sinclair's amounts reflect allocated expenses through February 12, 2017. The 2017 allocated expenses are detailed in the table below:

Name	Retirement Plan Expense	Savings Plan Expense
Benjamin M. Fink	$ 101,047	$ 37,451
Jaime R. Casas	53,119	18,488
Craig W. Collins	35,872	13,218
Philip H. Peacock	36,561	13,537
Donald R. Sinclair	9,312	3,666

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Grants of Plan-Based Awards in 2017

The following table sets forth information concerning annual incentive awards, stock options, phantom units, restricted stock shares, restricted stock units and performance units granted during 2017 to each of the named executive officers. Except for amounts in the column entitled Exercise or Base Price of Option Awards, the dollar amounts and number of securities included in the table below reflect an allocation based upon each named executive officer's allocation of time to Partnership business. Mr. Sinclair did not receive any grants in 2017.

	Estimated Future Payouts Under Non-Equity Incentive Plan Awards (1)			Estimated Future Payouts Under Equity Incentive Plan Awards (2)			All Other Stock Awards: Number of Shares of Stock or Units (#) (3)	All Other Option Awards: Number of Securities Underlying Options (#) (4)	Exercise or Base Price of Option Awards ($/Sh)	Grant Date Fair Value of Stock and Option Awards ($) (5)
Name and Grant Date	Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)				
Benjamin M. Fink										
—	—	325,122	390,146							
02/13/17								10,365	68.14	235,198
02/13/17				1,393	3,482	6,964				281,528
02/13/17							2,477			168,769
11/14/17								57,803	48.05	866,754
11/14/17				7,268	18,169	36,338				993,674
11/14/17							12,878			618,793
Jaime R. Casas										
—	—	135,675	162,810							
05/22/17								29,174	53.35	495,194
05/22/17							9,279			495,035
11/14/17								27,325	48.05	409,740
11/14/17				3,436	8,590	17,180				469,765
11/14/17							6,088			292,509
Craig W. Collins										
—	—	91,209	109,451							
02/13/17								7,678	68.14	174,209
02/13/17				1,032	2,580	5,160				208,553
02/13/17							1,835			125,003
11/14/17								7,007	48.05	105,063
11/14/17				881	2,203	4,406				120,455
11/14/17							10,406			