Western Gas Partners LP
Form 10-K
February 20, 2019

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, 2018

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 every Interactive Data File required to be submitted 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 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, a 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 ¨

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 $4.9 billion on June 29, 2018, based on the closing price as reported on the New York Stock Exchange.

At February 18, 2019, there were 152,609,285 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, FRP, Whitethorn and Cactus II.

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.

Cactus II: Cactus II Pipeline LLC.

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, part of the West Texas complex effective January 1, 2018.

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, part of the West Texas complex effective January 1, 2018.

DBM water systems: Two produced water gathering and 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.

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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.
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, 33.33% share of average FRP throughput and 20% share of average Whitethorn 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 NGLs volumes nominated by customers and gas and NGLs volumes received from those customers and (ii) differences between gas and NGLs volumes received from customers and gas and NGLs 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: Thousand barrels per day.
Merger: The merger of Clarity Merger Sub, LLC, a wholly owned subsidiary of WGP, with and into the Partnership, with the Partnership continuing as the surviving entity and a subsidiary of WGP, which is expected to close in the first quarter of 2019.

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Merger Agreement: The Contribution Agreement and Agreement and Plan of Merger, dated November 7, 2018, by and among WGP, the Partnership, Anadarko and certain of their affiliates, pursuant to which the parties thereto agreed to effect the Merger and certain other transactions.
MGR: Mountain Gas Resources, LLC.
MGR assets: The Red Desert complex and the Granger straddle plant.
MIGC: MIGC, LLC.
MLP: Master limited partnership.
MMBtu: Million British thermal units.
MMcf: Million cubic feet.
MMcf/d: 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 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.

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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.
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.
West Texas complex: The DBM complex and DBJV and Haley systems, all of which were combined into a single complex effective January 1, 2018.
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.
Whitethorn LLC: Whitethorn Pipeline Company LLC.
364-day Facility: Our 364-day senior unsecured credit agreement.
$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 and condensate on behalf of ourselves and as agent for our customers under certain of our contracts. We provide these midstream services for Anadarko, as well as for third-party 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.

Merger transactions. On November 7, 2018, WGP, the Partnership, Anadarko and certain of their affiliates entered into a Contribution Agreement and Agreement and Plan of Merger (as may be amended from time to time, the "Merger Agreement"), pursuant to which, among other things, Clarity Merger Sub, LLC, a wholly owned subsidiary of WGP, will merge with and into the Partnership, with the Partnership continuing as the surviving entity and a subsidiary of WGP (the "Merger"). Upon closing of the Merger, which is expected to occur in the first quarter of 2019, the common units of the Partnership will no longer be publicly traded and will cease to trade on the NYSE under the symbol "WES." The common units of WGP will begin trading on the NYSE under the symbol "WES" and WGP will change its name to Western Midstream Partners, LP.

The Merger Agreement also provides that WGP, the Partnership and Anadarko will, and will cause their respective affiliates to, cause the following transactions, among others, to occur immediately prior to the Merger becoming effective in the order as follows: (1) Anadarko E&P Onshore LLC and WGR Asset Holding Company LLC ("WGRAH") (the "Contributing Parties") will contribute to the Partnership all of their interests in each of Anadarko Wattenberg Oil Complex LLC, Anadarko DJ Oil Pipeline LLC, Anadarko DJ Gas Processing LLC, Wamsutter Pipeline LLC, DBM Oil Services, LLC, Anadarko Pecos Midstream LLC, Anadarko Mi Vida LLC and APC Water Holdings 1, LLC ("APCWH") to WGR Operating, LP, Kerr-McGee Gathering LLC and Delaware Basin Midstream, LLC (each wholly owned by the Partnership) in exchange for aggregate consideration of $1.814 billion in cash from the Partnership, minus the outstanding amount payable pursuant to an intercompany note ("APCWH Note Payable") to be assumed by the Partnership in connection with the transaction, and 45,760,201 of our common units; (2) AMH will sell to the Partnership its interests in Saddlehorn Pipeline Company, LLC and Panola Pipeline Company, LLC in exchange for aggregate consideration of $193.9 million in cash; (3) the Partnership will contribute cash in an amount equal to the outstanding balance of the APCWH Note Payable immediately prior to the effective time to APCWH, and APCWH will pay such cash to Anadarko in satisfaction of the APCWH Note Payable; (4) Class C units will convert into our common units on a one-for-one basis; and (5) the Partnership and its general partner will cause the conversion of the IDRs and the 2,583,068 general partner units held by the general partner into a non-economic general partner interest in us and 105,624,704 of our common units. The 45,760,201 of our common units to be issued to the Contributing Parties, less 6,375,284 common units to be retained by WGRAH, will be converted into the right to receive an aggregate of 55,360,984 WGP common units upon the consummation of the Merger. See Note 13—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for additional information.

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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 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.

OUR ASSETS AND AREAS OF OPERATION

As of December 31, 2018, our assets and investments consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Gathering systems [(1)]	12	2	3	2
Treating facilities	14	3	—	3
Natural gas processing plants/trains	21	3	—	2
NGLs pipelines	2	—	—	3
Natural gas pipelines	5	—	—	—
Oil pipelines	—	1	—	2

(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, 2018, excluding Mentone Train II at the West Texas complex and the Latham processing plant at the DJ Basin complex, which are currently under construction in West Texas and Colorado, respectively, (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)] [(2)]	Processing or Treating Capacity (MMcf/d) [(1)]	Processing, Treating or Disposal Capacity (MBbls/d) [(1)]	Average Gathering, Processing, Treating and Transportation Throughput (MMcf/d) [(3)]	Average Gathering, Treating, Transportation and Disposal Throughput (MBbls/d) [(4)]
Rocky Mountains	Gathering, Processing and Treating	6,894	3,584	536,470	3,250	14	2,228	—
	Transportation	1,500	57	—	—	—	79	26
Texas / New Mexico	Gathering, Processing, Treating and Disposal	2,544	1,114	615,361	1,370	414	1,485	183
	Transportation	1,647	19	—	—	—	—	156
	Gathering	146	59	9,660	—	—	100	—

North-central Pennsylvania							
Total	12,731	4,833	1,161,491	4,620	428	3,892	365

(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. Includes bypass capacity at the DJ Basin and West Texas complexes.

(2) Excludes compression horsepower for transportation.

(3) Includes 100% of Chipeta throughput, a 50.1% share of Springfield gas gathering throughput, a 22% share of Rendezvous throughput and a 14.81% share of Fort Union throughput.

(4) Consists of throughput on the Chipeta NGL pipeline, an NGLs line at the Brasada complex and at the DBM water systems, a 50.1% share of Springfield oil gathering throughput, a 10% share of White Cliffs throughput, a 25% share of Mont Belvieu JV throughput, a 20% share of TEG and TEP throughput, a 33.33% share of FRP throughput and a 20% share of Whitethorn throughput. See Properties below for further descriptions of these systems.

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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 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, 2018, 2017 and 2016.

ACQUISITIONS AND DIVESTITURES

Whitethorn LLC acquisition. In June 2018, we acquired a 20% interest in Whitethorn LLC, which owns a crude oil and condensate pipeline that originates in Midland, Texas and terminates in Sealy, Texas (the “Midland-to-Sealy pipeline”) and related storage facilities (collectively referred to as “Whitethorn”). A third party operates Whitethorn and oversees the related commercial activities. In connection with our investment in Whitethorn, we will share proportionally in the commercial activities. We acquired our 20% interest via a $150.6 million net investment, which was funded with cash on hand and is accounted for under the equity method.

Cactus II acquisition. In June 2018, we acquired a 15% interest in Cactus II, which will own a crude oil pipeline operated by a third party (the “Cactus II pipeline”) connecting West Texas to the Corpus Christi area. The Cactus II pipeline is under construction and is expected to become operational in late 2019. We acquired our 15% interest from a third party via an initial net investment of $12.1 million, which represented our share of costs incurred up to the date of acquisition. The initial investment was funded with cash on hand and the interest in Cactus II is accounted for under the equity method.

Newcastle system divestiture. In December 2018, the Newcastle system, located in Northeast Wyoming, was sold to a third party for $3.2 million, resulting in a net gain on sale of $0.6 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations. We previously held a 50% interest in, and operated, the Newcastle system.

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, 2018 (see Note 10—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. Further, after an acquisition of assets from Anadarko, we are 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.

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 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.

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- Managing commodity price exposure. We intend to continue limiting our direct exposure to commodity price changes and promote cash flow stability by pursuing a contract structure designed to mitigate exposure to a substantial majority of the commodity price uncertainty through the use of fee-based contracts.

- 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.

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.

- Substantial presence in basins with historically strong producer economics. Certain of our systems are in areas, such as the Delaware and DJ Basins, 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.

- Commodity price and volumetric risk mitigation. We believe a substantial majority of our cash flows are protected from direct fluctuations caused by commodity price volatility, as 89% of our wellhead natural gas volumes (excluding equity investments) and 100% of our crude oil and produced water throughput (excluding equity investments) were attributable to fee-based contracts for the year ended December 31, 2018. 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, 2018, 64% of our natural gas throughput and 71% of our crude oil, NGLs and produced water throughput were supported by either minimum volume commitments with associated deficiency payments or cost of service commitments.

- 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, 2018, we had $1.3 billion in available borrowing capacity under the RCF.

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- Consistent track record of accretive acquisitions. Since our IPO in 2008, our management team has successfully executed eleven related-party acquisitions and nine third-party acquisitions, with an aggregate acquisition value of $6.5 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.

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, 2018, WGP held 50,132,046 of our common units, representing a 29.6% 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, 2018, other subsidiaries of Anadarko collectively held 2,011,380 common units and 14,372,665 Class C units, representing an aggregate 9.7% limited partner interest in us. As of December 31, 2018, the public held 100,465,859 common units, representing the remaining 59.2% limited partner interest in us.

For the year ended December 31, 2018, production owned or controlled by Anadarko represented (i) 7% 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) 73% of our crude oil, NGLs 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.

During 2018, we had commodity price swap agreements with Anadarko to mitigate exposure to the commodity price risk inherent in our percent-of-proceeds, percent-of-product and keep-whole contracts at the DJ Basin complex and the MGR assets. These commodity price swap agreements expired without renewal on December 31, 2018. See Note 6—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 gathered and 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 service provider 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, a customer provides liquids rich gas volumes to the service provider for processing. The service provider is obligated to return the equivalent gas volumes to the customer subsequent to processing. Due to the use and loss of volumes in processing, the service provider must purchase additional volumes to compensate the customer. In these arrangements, the service provider receives all or a portion of the NGLs produced in consideration for the service provided. These type of arrangements can expose the service provider to high levels of commodity price exposure associated with the volumes purchased to keep the customer whole, as well as for the consideration received.

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, 2018.

GATHERING, PROCESSING AND TREATING

Overview - Rocky Mountains - Colorado and Utah

Location	Asset	Type	Processing / Treating Plants	Processing / Treating Capacity (MMcf/d) [1]	Processing / Treating Capacity (MBbls/d)	Compressors	Compression Horsepower	Gathering Systems	Pipeline Miles
Colorado	DJ Basin complex [2]	Gathering, Processing & Treating	10	1,010	14	120	302,187	2	3,215
Utah	Chipeta [3]	Processing	3	790	—	12	74,875	—	2
Total			13	1,800	14	132	377,062	2	3,217

(1) Includes 160 MMcf/d of bypass capacity at the DJ Basin complex.
(2) 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 and the Wattenberg gathering system.
(3) We are the managing member of and own a 75% interest in Chipeta, which owns the Chipeta processing complex.

DJ Basin gathering, treating and processing complex

- Customers. As of December 31, 2018, throughput at the DJ Basin complex was from Anadarko and numerous third-party customers. For the year ended December 31, 2018, Anadarko's production represented 65% of the DJ Basin complex throughput and the largest third-party customer provided 14% of the throughput.

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- Supply. The DJ Basin complex is primarily supplied by the Wattenberg field. There were 2,122 active receipt points connected to the DJ Basin complex as of December 31, 2018. Anadarko holds interests in approximately 645,000 gross (460,000 net) acres within the DJ Basin and during the year ended December 31, 2018, turned 278 operated wells to sales in the DJ Basin.

- Delivery points. As of December 31, 2018, 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 NGLs takeaway. In addition, the NGLs fractionator at the Platte Valley plant and associated truck-loading facility provides access to local NGLs markets.

Chipeta processing complex

- Customers. As of December 31, 2018, throughput at the Chipeta complex was from Anadarko and numerous third-party customers. For the year ended December 31, 2018, Anadarko's production represented 74% of the Chipeta complex throughput and the largest third-party customer provided 15% of the throughput.

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- Supply. The Chipeta complex is well positioned to access Anadarko and third-party production in the Uinta Basin where Anadarko holds interests in 244,000 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").

- 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 NGLs 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

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	14,645	—	—
Northeast Wyoming	Fort Union [(1)]	Gathering & Treating	3	295	3	5,454	1	315
Northeast Wyoming	Hilight	Gathering & Processing	2	60	34	36,554	1	1,232
Southwest Wyoming	Granger complex [(2)]	Gathering & Processing	4	520	41	44,967	1	738
Southwest Wyoming	Red Desert complex [(3)]	Gathering & Processing	1	125	25	50,303	1	1,054
Southwest Wyoming	Rendezvous [(4)]	Gathering	—	—	5	7,485	1	338
Total			13	1,450	117	159,408	5	3,677

(1) We have a 14.81% interest in Fort Union.
(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.

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Northeast Wyoming

Bison treating facility

- Customers. Throughput at the Bison treating facility was from two third-party customers as of December 31, 2018. The largest customer provided 75% of the throughput for the year ended December 31, 2018. 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.

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Fort Union gathering system and treating facility

- Customers. Moriah Powder River, LLC holds a majority of the firm capacity on the Fort Union system. To the extent capacity on the system is not used by this customer, 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 from the Powder River Basin near Gillette, Wyoming that are either produced or gathered by the customer noted above and their affiliates. These volumes are gathered and treated under contracts with minimum volume commitments.

- 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.

Hilight gathering system and processing plant

- Customers. As of December 31, 2018, gas gathered and processed through the Hilight system was from numerous third-party customers. The four largest producers provided 72% of the system throughput for the year ended December 31, 2018.

- 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 NGLs pipeline, resulting in all fractionated NGLs being sold locally through truck and rail loading facilities.

Southwest Wyoming

Granger gathering and processing complex

- Customers. As of December 31, 2018, throughput at the Granger complex was from numerous third-party customers. The two largest third-party customers provided 78% of the Granger complex throughput for the year ended December 31, 2018.

- Supply. The Granger complex is supplied by the Moxa Arch and the Jonah and Pinedale Anticline fields. The Granger gas gathering system had 577 active receipt points as of December 31, 2018.

- 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 and processing complex

- Customers. As of December 31, 2018, throughput at the Red Desert complex was from Anadarko and numerous third-party customers. For the year ended December 31, 2018, 40% of the Red Desert complex throughput was from the two largest third-party customers and 2% 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, 2018, 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) (1)	Processing / Treating / Disposal Capacity (MBbls/d)	Compressors / Pumps (2)	Compression Horsepower (2)	Gathering Systems	Pipeline Miles (3)
West Texas / New Mexico	West Texas complex (4)	Gathering, Processing & Treating	12	1,170	34	246	405,445	3	1,620
West Texas	DBM water systems	Gathering & Disposal	—	—	120	19	7,250	2	46
East Texas	Mont Belvieu JV (5)	Processing	2	—	170	—	—	—	—
South Texas	Brasada complex	Gathering, Processing & Treating	3	200	15	14	30,450	1	57
South Texas	Springfield system (6)	Gathering and Treating	3	—	75	107	172,216	2	821
Total			20	1,370	414	386	615,361	8	2,544

(1) Includes 70 MMcf/d of bypass capacity at the West Texas complex.
(2) Includes owned, rented and leased compressors and compression horsepower.
(3) Includes 18 miles of transportation related to the Ramsey Residue Lines at the West Texas complex.
(4)

The West Texas complex includes the DBM complex and DBJV and Haley systems. Excludes 2,000 gpm of amine treating capacity.

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

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

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West Texas gathering, treating and processing complex

- Customers. As of December 31, 2018, throughput at the West Texas complex was from Anadarko and numerous third-party customers. For the year ended December 31, 2018, Anadarko’s production represented 30% of the West Texas complex throughput and the largest third-party customer provided 11% of the throughput.

- Supply. Supply of gas and NGLs for the complex comes from production from the Delaware Sands, Avalon Shale, Bone Spring, Wolfcamp and Penn 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.

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- 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 within the West Texas complex for processing, while lean gas is delivered into Enterprise GC, L.P.'s pipeline for ultimate delivery into Energy Transfer LP's ("ET") Oasis pipeline (the "Oasis pipeline"). Residue gas from the Bone Spring and Mi Vida plants is delivered into the Oasis pipeline or Transwestern Pipeline Company LLC's pipeline. Residue gas produced at the West Texas complex is delivered to ET's Red Bluff Express pipeline and the Ramsey Residue Lines, which extend from the complex to the south and to the north, with both lines connecting with Kinder Morgan, Inc.'s interstate pipeline system. NGLs production is delivered into the Sand Hills pipeline, Lone Star NGL LLC's pipeline and EPIC Y-Grade Pipeline, LP's NGL pipeline. See Note 3—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

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

- Customers. As of December 31, 2018, throughput at the DBM water systems was from Anadarko and four third-party producers. Anadarko's production represented 98% of the throughput for the year ended December 31, 2018.

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

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 NGLs fractionation complex in Mont Belvieu, Texas.

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- 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.

Brasada gathering, stabilization, treating and processing complex

- Customers. Throughput at the Brasada complex was from one third-party customer as of December 31, 2018.

- 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, 2018.

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

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• 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, ET 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.

Overview - North-central Pennsylvania

Location	Asset	Type	Compressors	Compression Horsepower	Gathering Systems	Pipeline Miles
North-central Pennsylvania	Marcellus [1]	Gathering	7	9,660	3	146

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

Marcellus gathering systems

• Customers. As of December 31, 2018, the Marcellus Interest gathering systems had multiple priority shippers. The largest producer provided 86% of the throughput for the year ended December 31, 2018. Capacity not used by priority shippers is available to third parties as determined by the operating partner, Alta Resources Development, LLC.

• 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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Location	Asset	Type	Pipeline Miles
Colorado, Kansas, Oklahoma	White Cliffs [(1)] [(2)]	Oil	1,054
Utah	GNB NGL [(1)]	NGLs	33
Northeast Wyoming	MIGC [(1)]	Gas	239
Southwest Wyoming	OTTCO	Gas	174
Colorado, Oklahoma, Texas	FRP [(1)] [(3)]	NGLs	447
Texas, Oklahoma	TEG [(3)]	NGLs	191
Texas	TEP [(1)] [(3)]	NGLs	593
Texas	Whitethorn [(4)]	Oil	416
Total			3,147

(1) White Cliffs, GNB NGL, MIGC, FRP and TEP 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.
(4) We own a 20% interest in Whitethorn, which is operated by a third party.

Rocky Mountains - Colorado

White Cliffs pipeline

- Customers. The White Cliffs pipeline had multiple committed shippers, including Anadarko, as of December 31, 2018. In addition, other parties may ship on the White Cliffs pipeline at FERC-based rates. The White Cliffs dual pipeline system provides crude oil takeaway capacity of approximately 190 MBbls/d from Platteville, Colorado to Cushing, Oklahoma. During 2019, one of the pipelines will be converted from crude service to NGL Y-grade service with an initial capacity of 90 MBbls/d. To achieve this, the pipeline will be taken out of service in early 2019 and is expected to come back online during the fourth quarter of 2019.

- Supply. The White Cliffs pipeline is supplied by production from the DJ Basin. At the point of origin, there is a storage facility adjacent to a truck-unloading facility.

- 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.

Rocky Mountains - Utah

GNB NGL pipeline

- Customers. Anadarko was the only shipper on the GNB NGL pipeline as of December 31, 2018.

- 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 NGLs 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 85% of the throughput for the year ended December 31, 2018. The remaining throughput on the MIGC system was from numerous third-party shippers. MIGC is certificated for 175 MMcf/d of firm transportation capacity.

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- 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.

- 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, 2018, 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 30 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 and Adams Counties, Colorado (including the Lancaster plant, which is within the DJ Basin complex and Anadarko's Wattenberg plant) (see Rocky Mountains—Colorado and Utah within these Items 1 and 2). FRP connects to TEP near Skellytown, Texas. As of December 31, 2018, FRP had multiple committed shippers, including Anadarko. FRP provides capacity to other shippers at the posted FERC tariff rate. In 2018, we elected to participate in the expansion of FRP, which will increase capacity by 100 MBbls/d, to a targeted total capacity of 258 MBbls/d, with the expansion expected to be completed in 2019.

- Texas Express Gathering. TEG consists of two NGLs gathering systems that provide plants in North Texas, the Texas panhandle and West Oklahoma with access to NGLs takeaway capacity on TEP. TEG had one committed shipper as of December 31, 2018. In 2018, we participated in the expansion of the Texas/Oklahoma system of TEG, which has a total capacity of 100 MBbls/d and was completed in the second quarter of 2018.

- Texas Express Pipeline. TEP delivers to NGLs fractionation and storage facilities in Mont Belvieu, Texas. TEP is supplied with NGLs from other pipelines including FRP, the MAPL pipeline and TEG. As of December 31, 2018, TEP had multiple committed shippers, including Anadarko. TEP provides capacity to other shippers at the posted FERC tariff rates. In 2018, we elected to participate in the expansion of TEP, which will increase capacity by 90 MBbls/d, to a targeted total capacity of 348 MBbls/d, with the expansion expected to be completed in 2019.

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Whitethorn

Supply and delivery points. Whitethorn is supplied by production from the Permian Basin. Whitethorn transports crude oil and condensate from Enterprise’s Midland terminal to Enterprise’s Sealy terminal. From Sealy, shippers have access to Enterprise’s Rancho II pipeline, which extends to Enterprise’s ECHO terminal located in Houston, Texas. From ECHO, shippers have access to refineries in Houston, Texas City, Beaumont and Port Arthur, Texas, as well as Enterprise’s crude oil export facilities.

Assets Under Development

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

- Mentone Train II. We are currently constructing a second cryogenic processing train at the Mentone processing plant at the West Texas complex. Mentone Train II will have a capacity of 200 MMcf/d, and we expect this train to be completed in the first quarter of 2019. Upon completion of Mentone Train II, the West Texas complex will have a total processing capacity of 1,370 MMcf/d.

- Latham processing plant. We are currently constructing two cryogenic processing trains at a new processing plant located in Weld County, Colorado. Latham Trains I and II will each have a capacity of 200 MMcf/d. Latham Train I is expected to be completed in mid-2019 and Latham Train II is expected to be completed around year-end 2019. 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 1,410 MMcf/d.

- Equity investments. We are currently contributing to the construction of the Cactus II pipeline, a crude oil pipeline connecting West Texas to the Corpus Christi area. The Cactus II pipeline will have a total capacity of 670 MBbls/d upon completion and is expected to become operational in late 2019.

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 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, 2018.

Asset	Competitor(s)
Bison facility	Thunder Creek Gas Services, LLC and Fort Union (treating only)
Brasada complex	Enterprise, ET, Targa Resources Partners LP, Kinder Morgan, Inc., Plains All American Pipeline and Howard Energy Partners
Chipeta complex	Andeavor and Kinder Morgan, Inc.
DBM water systems	NGL Water Solutions, LLC, Mesquite SWD, Inc., Oilfield Water Logistics, LLC and Hillstone Environmental Partners, LLC
DJ Basin complex	DCP, AKA Energy Group, LLC, Rocky Mountain Midstream LLC and Cureton Midstream, LLC
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
Hilight system	ONEOK Gas Gathering Company, Thunder Creek Gas Services, LLC, Crestwood Midstream Partners LP, Tallgrass Energy Partners, LP and Evolution Midstream
Marcellus Interest gathering systems	ET and National Fuel Gas Midstream Corporation
Mont Belvieu JV	Targa Resources Partners LP, Phillips 66, Lone Star NGL LLC and ONEOK Partners, LP
Red Desert complex	Williams Field Services Company, LLC and Andeavor
Rendezvous system	No significant direct competition
Springfield system	Enterprise, ET, 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
West Texas complex	ET, 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

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. Whitethorn competes with Magellan Midstream Partners, L.P.'s Longhorn pipeline and BridgeTex Pipeline Company, LLC's pipeline.

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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, NGLs 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.

Legislation adopted in recent years has resulted in more stringent mandates for pipeline safety and has charged PHMSA with developing and adopting regulations that impose increased pipeline safety requirements on pipeline operators. The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (the "2011 Pipeline Safety Act"), which became law in January 2012, amended the NGPSA and HLPSA by increasing the penalties for safety violations, establishing additional safety requirements for newly constructed pipelines and requiring studies of safety issues that could result in the adoption of new regulatory requirements for existing pipelines. In June 2016, President Obama signed the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (the "2016 Pipeline Safety Act"), further amending the NGPSA and HLPSA, extending PHMSA's statutory mandate through 2019 and, among other things, requires PHMSA to complete certain of the outstanding mandates under the 2011 Pipeline Safety Act and empowers the agency 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 2016 to implement the agency's expanded authority over imminent pipeline hazards.

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, implementation of this final rule by publication in the Federal Register has been delayed following the January 2017 change from the Obama to Trump presidential administrations. In a second example, 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 split this rule into three separate rulemaking proceedings and is expected to finalize these proceedings in 2019.

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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.

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 U.S. 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.

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Natural gas companies are prohibited from charging rates that have been determined not to be just and reasonable by FERC. In addition, FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.
The rates and terms and conditions for our interstate pipeline services are set forth in FERC-approved tariffs. Pursuant to FERC's jurisdiction over rates, existing rates may be challenged by complaint or by action of FERC under Section 5 of the NGA, and proposed rate increases may be challenged by protest. The outcome of any successful complaint or protest against our rates could have an adverse impact on revenues associated with providing transportation service. For example, one such matter relates to FERC's policy regarding allowances for income taxes in determining a regulated entity's cost of service. 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. On March 15, 2018, as clarified on July 18, 2018, in a set of related issuances, FERC addressed treatment of federal income tax allowances in regulated entity rates. To the extent a regulated entity is permitted to include an income tax allowance in its cost of service, FERC directed entities to calculate the income tax allowance at the reduced 21% maximum corporate tax rate established by the Tax Cuts and Jobs Act of 2017. FERC also issued the Revised Policy on Treatment of Income Taxes ("Revised Policy Statement") stating that it will no longer permit MLPs to recover an income tax allowance in their cost of service rates. FERC has noted that to the extent an entity does not include an income tax allowance in their cost of service rates, such entity may elect to also exclude the accumulated deferred income tax balance from the rate calculation. FERC's Revised Policy Statement may result in an adverse impact on revenues associated with the cost of service rates of our FERC-regulated interstate pipelines.
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 NGLs 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 NGLs 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. White Cliffs has a pending request before FERC for authorization to charge market-based rates. We cannot predict the outcome of this matter or its potential effect on our revenues.

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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. FERC’s Revised Policy Statement, discussed above, that no longer permits MLPs to recover an income tax allowance in their cost of service rates, also applies to our pipelines regulated under the Interstate Commerce Act. The Revised Policy Statement may result in an adverse impact on our revenues associated with the cost of service rates of our FERC-regulated interstate pipelines.

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.

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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.

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 AND OCCUPATIONAL HEALTH AND SAFETY REGULATIONS

Our business operations are subject to numerous federal, regional, state, tribal, and local environmental and occupational health and safety laws and regulations. The more significant of these existing environmental laws and regulations include the following legal standards that currently exist in the United States, 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, operational, monitoring, and reporting requirements, and that 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 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 rulemaking as protected waters of the United States;

- the Oil Pollution Act of 1990, which subjects, among others, 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;

- regulations imposed by the Bureau of Land Management (the "BLM") and the Bureau of Indian Affairs, agencies under the authority of the U.S. Department of the Interior, which govern and restrict aspects of oil and natural gas operations on federal and Native American lands, including the imposition of liabilities for pollution damages and pollution clean-up costs resulting from such operations;

- 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;

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- 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 non-producing geologic 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;

- OSHA, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures;

- 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;

- 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 response preparedness.

Additionally, there exist regional, state, tribal and local jurisdictions in the United States where we operate that also have, or are developing or considering 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. These federal and state environmental laws and regulations, including new or amended legal requirements that may arise in the future to address potential environmental concerns such as air and water impacts and oil and natural gas development in close proximity to specific occupied structures and/or certain environmentally-sensitive or recreational areas, are expected to continue to have a considerable impact on our operations.

In connection with our operations, we have acquired certain properties supportive of oil and natural gas activities from third parties whose actions with respect to the management and disposal or release of hydrocarbons, hazardous substances or wastes were not under our control. Under environmental laws and regulations, we could incur strict joint and several liability for remediating hydrocarbons, hazardous substances or wastes disposed of or released by prior owners or operators. We also could incur costs related to the clean-up of third-party sites to which we sent regulated substances for disposal or recycling, and for damages to natural resources or other claims related to releases of regulated substances at or from such third-party sites.

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These federal and state laws and their implementing regulations 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 or cancellations 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. Moreover, there exist environmental laws that provide for citizen suits, which allow environmental organizations to act in the place of the government and sue operators for alleged violations of environmental law. See the following risk factors under Part I, Item 1A of this Form 10-K for further discussion on environmental matters such as ozone standards, climate change, including methane or other GHG emissions, hydraulic fracturing and other regulatory initiatives related to environmental protection: “We are subject to stringent and comprehensive environmental laws and regulations that may expose us to significant costs and liabilities,” “Adoption of new or more stringent 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 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” and “Adoption of new or more stringent legal standards relating to induced seismic activity associated with produced water disposal could affect our operations.” 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.

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 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 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 standards related to the disposal of produced water into non-producing geologic formations by means of underground injection wells are subject to change based on concerns of the public or governmental authorities, including concerns relating to 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. Another consequence of seismic events near produced water disposal wells is the introduction of class action lawsuits, which allege that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. One or more of 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 a 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, 2018, Anadarko employed 602 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 ability to consummate the Merger on the terms currently contemplated or at all;
- our and Anadarko’s assumptions about the energy market;
- future throughput (including Anadarko production) that 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;
- commodity price risks inherent in our percent-of-proceeds, percent-of-product and keep-whole contracts;
- 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, as well as state-approved voter ballot initiatives, including those laws or ballot initiatives that limit Anadarko’s and other producers’ hydraulic fracturing or other oil and natural gas development or 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, and continued or additional disruptions in operations that may occur as Anadarko and we comply with any regulatory orders or other state or local changes in laws or regulations; 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, 2018, production owned or controlled by Anadarko represented (i) 7% 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) 73% of our crude oil, NGLs 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, including state-approved ballot initiatives that would change state constitutions or statutes in a manner that makes future oil and gas development in such states more difficult or expensive;

- 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, and our $260.0 million note receivable from Anadarko. 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 and note receivable. 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, 2018 (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, NGLs or oil prices could adversely affect our business.

Sustained low natural gas, NGLs 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;
- 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.

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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.

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 2018 distribution of $0.980 per unit per quarter, or $3.920 per unit per year, we will require available cash of $234.8 million per quarter, or $939.1 million per year, based on the number of common units, general partner units and IDRs outstanding at February 1, 2019. 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.

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

- our level of capital expenditures;
- our level of operating and maintenance and general and administrative costs;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- our treatment as a flow-through entity for U.S. federal income tax purposes;
- restrictions contained in debt agreements to which we are a party; and
- the amount of cash reserves established by our general partner.

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.

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, 2018, 89% of our wellhead natural gas volumes (excluding equity investments) and 100% of our crude oil and produced water throughput (excluding equity investments) were attributable to fee-based contracts under which fixed and variable fees are 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. For the year ended December 31, 2018, 95% of our wellhead natural gas volumes (excluding equity investments) was attributable to either long-term, fee-based contracts, or percent-of-proceeds or keep-whole contracts that were hedged with commodity price swap agreements. See Note 6—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 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 NGLs prices and other changing market conditions. 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.

Our commodity price swap agreements with Anadarko for the DJ Basin complex and the MGR assets expired without renewal on December 31, 2018. In the future, we may seek to enter into third-party commodity price swap agreements or similar hedging arrangements, and 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 were not previously exposed, because the commodity price swap agreements with Anadarko were based on our actual volumes. Additionally, if we are unable to effectively manage the risk associated with our contracts that have commodity price exposure, it could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

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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 oil and natural gas exploration and production customers do conduct such activities. Hydraulic fracturing is an essential and common practice used by many of our 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 several federal agencies have also asserted regulatory authority over, proposed or promulgated regulations governing, and conducted investigations relating to certain aspects of the process, including the EPA and the BLM. For example, in late 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 certain circumstances. Additionally, in 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. Moreover, Congress has from time to time considered the adoption of legislation to provide for federal regulation of hydraulic fracturing.
At the state level, some states have adopted, and others are considering adopting, legal requirements that could impose more stringent disclosure, permitting 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. Local governments may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Moreover, non-governmental organizations may seek to restrict hydraulic fracturing, such as was the case in Colorado where certain interest groups therein have unsuccessfully pursued ballot initiatives in recent general election cycles that, had they been successful, would have revised the state constitution or state statutes in a manner that would have made exploration and production activities in the state more difficult or expensive in the future, including, for example, by increasing mandatory setback distances of oil and natural gas operations from specific occupied structures and/or certain environmentally-sensitive or recreational areas.
If new or more stringent federal, state or local legal restrictions, prohibitions or regulatory or ballot initiatives 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. Any one or more of these developments could have a material adverse effect on our business, financial condition and results of operations.

Adoption of new or more stringent legal standards relating to 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 into a non-producing geologic formation by means of 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. Another consequence of seismic events may be class action lawsuits, alleging 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, including a possible shut down of such wells, which could have a material adverse effect on our business, financial condition and results of operations.

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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.

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;
- 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.

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

Our indebtedness could have important consequences to us, including the following:

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

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

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

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

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

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

Interest rates may increase in the future, whether because of inflation, increased yields on U.S. Treasury obligations or otherwise. In such cases, the interest rates on our floating rate debt, including amounts outstanding under 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.

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.

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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. Additionally, destructive forms of protests and opposition by activists and other disruptions, including acts of sabotage or eco-terrorism, against oil and natural gas development and production or midstream processing or transportation activities could potentially result in damage or injury to persons, property or the environment or lead to extended interruptions of our or our clients' operations. 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. 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, 2018, on all of our common units, general partner units and IDRs was $234.8 million, or $939.1 million per year. The Class C unit distribution, if paid in cash, would have been $14.1 million for the quarter ended December 31, 2018. 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.

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.

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

We compete with similar enterprises in our areas of operation. Our competitors may expand or construct midstream systems that would create additional competition for the services we provide to our customers. In addition, our customers, including Anadarko, may develop their own midstream systems in lieu of using ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Our results of operations could be adversely affected by asset impairments.

If 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 in Note 8—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, 2018, 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.

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.

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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. For additional information, read Regulation of Operations—Interstate Liquids Pipeline Regulation under Items 1 and 2 of this Form 10-K.
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's Revised Policy Statement established that FERC will no longer permit master limited partnerships to recover an income tax allowance in their cost of service rates and noted that to the extent an entity does not include an income tax allowance in their cost of service rates, such entity may elect to also exclude the accumulated deferred income tax balance from the rate calculation. This policy may result in an adverse impact on our revenues associated with the cost of service rates of our FERC-regulated gas and liquids pipelines. For additional information, read Regulation of Operations—Interstate Natural Gas Pipeline Regulation and 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.

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Adoption of new or more stringent 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 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 under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. In 2017 and 2018, the EPA issued area designations with respect to ground-level ozone as either "attainment/unclassifiable," "unclassifiable" or "non-attainment." Additionally, in November 2018, the EPA issued final requirements that apply to state, local and tribal air agencies for implementing the 2015 NAAQS for ground-level ozone. State implementation of the revised NAAQS could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs.

- Reduction of Methane Emissions by the Oil and Gas Industry. In 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 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. In February 2018, the EPA finalized amendments to certain requirements of the 2016 final rule and, in September 2018, the agency proposed amendments that included rescission or revision of specified rule requirements, such as fugitive emission monitoring frequency. In a separate rulemaking, the BLM published a final rule in late 2016 that requires a reduction in methane emissions by regulating venting, flaring and leaking from oil and natural gas operations on public lands; however, in September 2018, the BLM published a final rule rescinding most of the new requirements of the 2016 final rule and codifying the BLM's prior approach to venting and flaring, which rescission has been challenged in federal court and remains pending. Notwithstanding the 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 conduct operations, 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 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. Additionally, in April 2016, the United States joined other countries in entering into a United Nations-sponsored non-binding agreement negotiated in Paris, France ("Paris Agreement") for nations to limit their GHG emissions through individually-determined reduction goals every five years beginning in 2020. However, in August 2017, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The implementation of substantial limitations on GHG emissions in areas where we conduct operations could result in increased compliance costs to acquire emissions allowances or comply with new regulatory or reporting requirements, which developments could adversely affect demand for oil and natural gas that our customers produce, reduce demand for our services and have a material adverse effect on our business, financial condition and results of operation.

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.

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 such as, for example, PHMSA's January 2017 final rule for hazardous liquid pipelines that is yet to be published in the Federal Register and implemented and PHMSA's March 2016 proposed rulemaking for gas pipelines, could result in a material adverse effect on our results of operations or financial position.

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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.

Legislation adopted in recent years has resulted in more stringent mandates for pipeline safety and has charged PHMSA with developing and adopting regulations that impose increased pipeline safety requirements on pipeline operators. In 2016, President Obama signed the 2016 Pipeline Safety Act that extends PHMSA's statutory mandate regarding pipeline safety through 2019 expands PHMSA's authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property, or the environment, and requires the agency to complete certain of its outstanding mandates established under the 2011 Pipeline Safety Act. The imposition of new safety requirements pursuant to these enacted laws 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 capital expenditures and 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 for hazardous liquid pipelines, 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 has been delayed following the January 2017 change from the Obama to Trump 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 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 split this rule into three separate rulemaking proceedings and is expected to finalize these proceedings in 2019.

Additionally, 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. Moreover, 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 NGLs 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 NGLs 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.

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.

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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 restoration and remedial liabilities and obligations with respect to abandonment of facilities and 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, including administrative, civil and criminal penalties, the imposition of investigatory, remedial or corrective action obligations, the incurrence of capital expenditures, the occurrence of delays or cancellations 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 pollutants from our operations emitted into ambient air or discharged or released into surface water or groundwater, 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 restoration or remedial actions that may become necessary, which could have a material adverse effect on our results of operations or financial condition. 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 and, while subject to further implementation or various legal impediments, could result in increased compliance costs. The adoption of these or any other laws, regulations or other legally enforceable mandates could increase our oil and natural gas exploration and production 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.

In addition, the legal requirements related to the disposal of produced water into non-producing geologic 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 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, 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 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. Another consequence of seismic events may be class action lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. One or more of 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.

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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. For example, construction activities may be delayed or require greater capital investment if the commodity prices of certain supplies such as steel pipe increase due to foreign tariffs. 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.

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.

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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. We cannot guarantee that we will always be able to renew existing rights of way or obtain new rights of way without experiencing significant costs. Any loss of rights with respect to our real property, through our inability to renew existing rights-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, property or natural resource damages and/or curtailment or suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental 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.

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.

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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 make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations on a per-unit basis.
Any acquisition involves potential risks, including the following, among other things:

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

If we consummate any future acquisitions, our capitalization and results of operations may change significantly.

The 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 a 77.8% 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.

- 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 28.8 million 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. 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 a 77.8% limited partner interest in WGP, financial incentive to continue to grow our business over time, 34.4% 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 2018. 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. If the Merger Agreement and the transactions contemplated thereby are not approved by our unitholders, or such transactions are not otherwise consummated, we may need to evaluate alternative transactions that would result in a simplification of our capital structure, including the potential modification or elimination of our IDRs. Future evaluation of any such alternative transaction 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 alternative transaction. If consummated, an alternative 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 18, 2019, WGP owned a 29.5% limited partner interest in us. Other subsidiaries of Anadarko separately owned an aggregate 9.9% limited partner interest in us, consisting of common and Class C units. As such, Anadarko has the ability to prevent the removal of our general partner.

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

Unitholders' voting rights are restricted by a provision of our partnership agreement providing that any person or group that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the Board of Directors, 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 18, 2019, WGP held 50,132,046 common units and other subsidiaries of Anadarko held 2,011,380 common units and 14,681,388 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 18, 2019, WGP owned a 29.5% limited partner interest in us, and other subsidiaries of Anadarko held an aggregate 9.9% 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 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 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, the Treasury Department has issued regulations interpreting the laws that affect publicly traded partnerships. We believe we qualify as a partnership for U.S. federal income tax purposes under these regulations. 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 the 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, subject to the Treasury Department's proposed aggregation rules regarding certain similarly situated businesses or activities, 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 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 recognized 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

Kerr-McGee Gathering LLC, 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." Upon closing of the Merger, our common units will no longer be publicly traded and will cease to trade on the NYSE. 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 additional information.
As of February 18, 2019, there were 22 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. Also, we have issued and outstanding 2,583,068 general partner units and 14,681,388 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, 2018, we issued 327,236 PIK Class C units with an implied fair value of $15.1 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. For more information, see Note 4—Partnership Distributions and Note 5—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K. All outstanding Class C units will convert into our common units on a one-for-one basis immediately prior to the closing of the Merger, if consummated. If the Merger is not consummated, the conversion will occur on March 1, 2020, unless we elect to convert such units earlier or Anadarko extends the conversion date. 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.

Securities authorized for issuance under equity compensation plans. The WES 2017 LTIP permits the issuance of up to 2,250,000 units, 2,241,980 of which remain available for future issuance as of December 31, 2018. Phantom unit grants under the WES 2017 LTIP have been made to each of the independent directors of our general partner. Read the information under Part III, Item 12 of this Form 10-K, which is incorporated by reference into this Item 5.

SELECTED INFORMATION FROM OUR PARTNERSHIP AGREEMENT

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

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General partner interest and incentive distribution rights. As of December 31, 2018, 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.

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, 2018 (see Note 10—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. Further, after an acquisition of assets from Anadarko, we are 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
TEFR Interests [(1)]	03/03/2014	Various [(1)]		Affiliate
DBM	11/25/2014	100	%	Third party
DBJV system	03/02/2015	50	%	Affiliate
Springfield system	03/14/2016	50.1	%	Affiliate
DBJV system [(2)]	03/17/2017	50	%	Third party
Whitethorn LLC [(3)]	06/01/2018	20	%	Third party
Cactus II [(3)]	06/27/2018	15	%	Third party

(1) Acquired a 20% interest in each of TEG and TEP and a 33.33% interest in FRP.
(2) See Property exchange below.
(3) See Note 3—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for additional details.

Property exchange. 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. We previously held a 50% interest in, and operated, the DBJV system.

Divestitures. In December 2018, the Newcastle system in Northeast Wyoming was sold to a third party. 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 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 with the information under the captions Items Affecting the Comparability of Our Financial Results, How We Evaluate Our Operations, 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 impact the adoption of ASU 2014-09, Revenue from Contracts with Customers (Topic 606) had on revenues and expenses.

thousands except per-unit data, throughput, Adjusted gross margin per Mcf and Adjusted gross margin per Bbl	Summary Financial Information				
	2018	2017	2016	2015	2014
Statement of Operations Data (for the year ended):					
Total revenues and other	$1,990,276	$2,248,356	$1,804,270	$1,752,072	$1,533,377
Cost of product	431,921	908,693	494,194	528,369	458,379
Operating income (loss)	629,393	707,271	708,208	157,330	554,731
Net income (loss)	454,384	578,218	602,294	14,207	456,668
Net income attributable to noncontrolling interest	8,609	10,735	10,963	10,101	14,025
Net income (loss) attributable to Western Gas Partners, LP	445,775	567,483	591,331	4,106	442,643
Net income (loss) per common unit – basic	0.55	1.30	1.74	(1.95)	2.13
Net income (loss) per common unit – diluted	0.55	1.30	1.74	(1.95)	2.12
Distributions per unit	3.830	3.590	3.350	3.050	2.650
Balance Sheet Data (at year end):					
Total assets	$9,236,282	$8,014,350	$7,733,028	$7,301,197	$7,549,785
Total long-term liabilities	5,197,121	3,619,006	3,281,944	3,147,681	2,699,244
Total equity and partners' capital	3,531,579	3,971,011	4,135,779	3,918,028	4,568,462
Cash Flow Data (for the year ended):					
Net cash flows provided by (used in):					
Operating activities	$1,020,634	$901,495	$917,585	$785,645	$694,495
Investing activities	(1,459,798)	(763,604)	(1,105,534)	(500,277)	(2,740,175)
Financing activities	450,798	(417,002)	447,841	(254,389)	2,011,970
Capital expenditures	(1,193,896)	(673,638)	(473,858)	(637,503)	(804,822)
Throughput (MMcf/d except throughput measured in barrels):					
Total throughput for natural gas assets	3,892	3,680	4,064	4,300	3,984
Throughput attributable to noncontrolling interest for natural gas assets	90	105	124	142	165
Total throughput attributable to Western Gas Partners, LP for natural gas assets	3,802	3,575	3,940	4,158	3,819
Throughput for crude oil, NGLs and produced water assets (MBbls/d)	365	201	184	186	154
Key Performance Metrics (for the year ended): [(1)]					
Adjusted gross margin for natural gas assets	$1,398,953	$1,222,632	$1,194,877	$1,119,555	$993,397
Adjusted gross margin for crude oil, NGLs and produced water assets	246,853	153,846	142,566	131,492	103,102
Adjusted gross margin per Mcf for natural gas assets	1.01	0.94	0.83	0.74	0.71
Adjusted gross margin per Bbl for crude oil, NGLs and produced water assets	1.85	2.10	2.11	1.93	1.84
Adjusted EBITDA	1,205,761	1,060,988	1,028,208	907,568	782,900
Distributable cash flow	958,707	928,967	852,446	781,383	661,133

(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, 2018 (see Note 10—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. Further, after an acquisition of assets from Anadarko, we are 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 and condensate on behalf of ourselves and as agent for our customers under certain of our contracts. We provide these midstream services for Anadarko, as well as for third-party customers. As of December 31, 2018, our assets and investments consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Gathering systems [1]	12	2	3	2
Treating facilities	14	3	—	3
Natural gas processing plants/trains	21	3	—	2
NGLs pipelines	2	—	—	3
Natural gas pipelines	5	—	—	—
Oil pipelines	—	1	—	2

(1) Includes the DBM water systems.

Significant financial and operational events during the year ended December 31, 2018, included the following:

- In August 2018, we completed an offering of $400.0 million aggregate principal amount of 4.750% Senior Notes due 2028 and $350.0 million aggregate principal amount of 5.500% Senior Notes due 2048. The net proceeds were used to repay the maturing 2.600% Senior Notes due August 2018, repay amounts outstanding under the RCF and for general partnership purposes, including to fund capital expenditures. See Liquidity and Capital Resources within this Item 7 for additional information.

- In June 2018, we acquired a 20% interest in Whitethorn and a 15% interest in Cactus II, both from third parties. See Acquisitions and Divestitures under Part I, Items 1 and 2 of this Form 10-K for additional information.

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- In March 2018, we completed an offering of $400.0 million aggregate principal amount of 4.500% Senior Notes due 2028 and $700.0 million aggregate principal amount of 5.300% Senior Notes due 2048. The net proceeds were used to repay amounts outstanding under the RCF and for general partnership purposes, including to fund capital expenditures. See Liquidity and Capital Resources within this Item 7 for additional information.

- In February 2018, we entered into the five-year $1.5 billion (expandable to $2.0 billion) RCF by amending and restating the $1.2 billion credit facility originally entered into in February 2014. In December 2018, we amended the RCF to (i) subject to consummation of the Merger (see Merger transactions below), increase the size of the RCF to $2.0 billion, and (ii) extend the maturity date of the RCF to February 2024. See Liquidity and Capital Resources within this Item 7 for additional information.

- We commenced operation of Mentone Train I at the West Texas complex (with capacity of 200 MMcf/d) in the fourth quarter of 2018.

- We raised our distribution to $0.980 per unit for the fourth quarter of 2018, representing a 2% increase over the distribution for the third quarter of 2018 and a 7% increase over the distribution for the fourth quarter of 2017, and resulting in a full-year 2018 distribution increase of 7% over full-year 2017.

- Throughput attributable to Western Gas Partners, LP for natural gas assets totaled 3,802 MMcf/d for the year ended December 31, 2018, representing a 6% increase compared to the year ended December 31, 2017.

- Throughput for crude oil, NGLs and produced water assets totaled 365 MBbls/d for the year ended December 31, 2018, representing an 82% increase compared to the year ended December 31, 2017.

- Operating income (loss) was $629.4 million for the year ended December 31, 2018, representing an 11% decrease compared to the year ended December 31, 2017.

- Adjusted gross margin for natural gas assets (as defined under the caption How We Evaluate Our Operations within this Item 7) averaged $1.01 per Mcf for the year ended December 31, 2018, representing a 7% increase compared to the year ended December 31, 2017.

- Adjusted gross margin for crude oil, NGLs and produced water assets (as defined under the caption How We Evaluate Our Operations within this Item 7) averaged $1.85 per Bbl for the year ended December 31, 2018, representing a 12% decrease compared to the year ended December 31, 2017.

Merger transactions. On November 7, 2018, WGP, the Partnership, Anadarko and certain of their affiliates entered into a Contribution Agreement and Agreement and Plan of Merger (as may be amended from time to time, the "Merger Agreement"), pursuant to which, among other things, Clarity Merger Sub, LLC, a wholly owned subsidiary of WGP, will merge with and into the Partnership, with the Partnership continuing as the surviving entity and a subsidiary of WGP (the "Merger"). Upon closing of the Merger, which is expected to occur in the first quarter of 2019, the common units of the Partnership will no longer be publicly traded and will cease to trade on the NYSE under the symbol "WES." The common units of WGP will begin trading on the NYSE under the symbol "WES" and WGP will change its name to Western Midstream Partners, LP.

The Merger Agreement also provides that WGP, the Partnership and Anadarko will, and will cause their respective affiliates to, cause the following transactions, among others, to occur immediately prior to the Merger becoming effective in the order as follows: (1) Anadarko E&P Onshore LLC and WGR Asset Holding Company LLC ("WGRAH") (the "Contributing Parties") will contribute to the Partnership all of their interests in each of Anadarko Wattenberg Oil Complex LLC, Anadarko DJ Oil Pipeline LLC, Anadarko DJ Gas Processing LLC, Wamsutter Pipeline LLC, DBM Oil Services, LLC, Anadarko Pecos Midstream LLC, Anadarko Mi Vida LLC and APC Water Holdings 1, LLC ("APCWH") to WGR Operating, LP, Kerr-McGee Gathering LLC and Delaware Basin Midstream, LLC (each wholly owned by the Partnership) in exchange for aggregate consideration of $1.814 billion in cash from the Partnership, minus the outstanding amount payable pursuant to an intercompany note ("APCWH Note Payable") to be assumed by the Partnership in connection with the transaction, and 45,760,201 of our common units; (2) AMH will sell to the Partnership its interests in Saddlehorn Pipeline Company, LLC and Panola Pipeline Company, LLC in exchange for aggregate consideration of $193.9 million in cash; (3) the Partnership will contribute cash in an amount equal to the outstanding balance of the APCWH Note Payable immediately prior to the effective time to APCWH, and APCWH will pay such cash to Anadarko in satisfaction of the APCWH Note Payable; (4) Class C units will convert into our common units on a one-for-one basis; and (5) the Partnership and its general partner will cause the conversion of the IDRs and the 2,583,068 general partner units held by the general partner into a non-economic general partner interest in us and 105,624,704 of our common units. The 45,760,201 of our common units to be issued to the Contributing Parties, less 6,375,284 common units to be retained by WGRAH, will be converted into the right to receive an aggregate of 55,360,984 WGP common units upon the consummation of the Merger.

See Note 13—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for additional information.

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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.

Gathering and processing agreements. Certain of the gathering agreements for the West Texas complex and Springfield system allow for rate resets that target an agreed-upon rate of return over the life of the agreement. See Note 6—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Commodity price swap agreements. During all periods presented, our consolidated statements of operations and consolidated statements of equity and partners' capital included the impacts of commodity price swap agreements. The commodity price swap agreements with Anadarko expired without renewal on December 31, 2018. See Note 6—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. For the year ended December 31, 2018, there was a net increase in Adjusted gross margin of $40.5 million related to our asset acquisitions and divestitures during 2018. For the year ended December 31, 2017, there was a net decrease in Adjusted gross margin of $48.2 million related to our asset acquisitions and divestitures during 2017. See Note 3—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for additional information.

DBM complex. In December 2015, there was an initial fire and secondary explosion at the processing facility within the 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. 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 second quarter of 2017, we reached a settlement with insurers and final proceeds were received. During the years ended December 31, 2017 and 2016, we 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. 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 2017, we recognized impairments of $178.4 million, including an impairment of $158.8 million at the Granger complex due to a reduced throughput fee as a result of a producer's bankruptcy. During 2018, we recognized impairments of $228.3 million, including impairments of (i) $125.9 million at the Third Creek gathering system (part of the DJ Basin complex) and $8.1 million at the Kitty Draw gathering system due to the shutdown of the systems, (ii) $38.7 million at the Hilight system and (iii) $34.6 million at the MIGC system. See Note 1—Summary of Significant Accounting Policies and Note 8—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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Adoption of Topic 606. On January 1, 2018, we adopted Revenue from Contracts with Customers (Topic 606) ("Topic 606"). The comparative historical financial information has not been adjusted and continues to be reported under Revenue Recognition (Topic 605). The following table summarizes the impact of adopting Topic 606 on the consolidated statement of operations:

	Year Ended December 31, 2018		
thousands	As Reported	Without Adoption of Topic 606	Effect of Change Increase / (Decrease)
Revenues			
Service revenues – fee based	$1,609,245	$1,499,424	$109,821
Service revenues – product based	85,553	—	85,553
Product sales	293,992	1,306,479	(1,012,487)
Expenses			
Cost of product	431,921	1,270,811	(838,890)
Operation and maintenance	414,784	414,591	193
Depreciation and amortization	337,536	334,551	2,985
Impairments	228,338	228,293	45
Income tax expense (benefit)	2,946	2,816	130

For more information on the adoption of Topic 606, 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 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 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 and West Texas. For example, for the year ended December 31, 2018, the DJ Basin and West Texas complexes provided 30% and 28%, respectively, of our throughput for natural gas assets (excluding equity investment throughput) and 38% and 26%, respectively, of our Adjusted gross margin.

For the year ended December 31, 2018, 54% of our total revenues and 38% of our throughput (on a per unit basis, assuming 1 Mcf equals 1 barrel, and excluding equity investment throughput) were attributable to transactions with Anadarko. We also recognized capital contributions from Anadarko of $51.6 million related to the above-market component of our commodity price swap agreements with Anadarko (see Note 6—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, 2018, 89% of our wellhead natural gas volumes (excluding equity investments) and 100% of our crude oil and produced water throughput (excluding equity investments) were attributable to fee-based contracts under which fixed and variable fees are 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, 2018, 95% of our wellhead natural gas volumes (excluding equity investments) was attributable to either long-term, fee-based contracts, as discussed above, or percent-of-proceeds or keep-whole contracts that were hedged with commodity price swap agreements. See Note 6—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 within this Item 7.

HOW WE EVALUATE OUR OPERATIONS

Our management relies on certain financial and operational metrics to analyze our performance. These metrics are significant factors in assessing our operating results and profitability and include (1) throughput, (2) 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, 2018, 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. 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 6—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

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 reimbursements for electricity-related expenses recorded as revenue), less cost of product, 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, percent-of-product and keep-whole 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.
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, NGLs 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 Service revenues – fee based recognized in Adjusted EBITDA (less than) in excess of customer billings, 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	2018	2017	2016
Reconciliation of Operating income (loss) to Adjusted gross margin			
Operating income (loss)	$629,393	$707,271	$708,208
Add:			
Distributions from equity investments	169,906	110,465	103,423
Operation and maintenance	414,784	315,994	308,010
General and administrative	59,706	47,796	45,591
Property and other taxes	42,934	46,818	40,145
Depreciation and amortization	337,536	290,874	272,933
Impairments	228,338	178,374	15,535
Less:			
Gain (loss) on divestiture and other, net	1,312	132,388	(14,641)
Proceeds from business interruption insurance claims	—	29,882	16,270
Equity income, net – affiliates	153,024	85,194	78,717
Reimbursed electricity-related charges recorded as revenues	66,580	56,823	59,733
Adjusted gross margin attributable to noncontrolling interest	15,875	16,827	16,323
Adjusted gross margin	$1,645,806	$1,376,478	$1,337,443
Adjusted gross margin for natural gas assets	$1,398,953	$1,222,632	$1,194,877
Adjusted gross margin for crude oil, NGLs and produced water assets	246,853	153,846	142,566

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thousands	Year Ended December 31, 2018	2017	2016
Reconciliation of Net income (loss) attributable to Western Gas Partners, LP to Adjusted EBITDA			
Net income (loss) attributable to Western Gas Partners, LP	$445,775	$567,483	$591,331
Add:			
Distributions from equity investments	169,906	110,465	103,423
Non-cash equity-based compensation expense	7,032	4,947	5,591
Interest expense	184,008	142,386	114,921
Income tax expense	3,301	4,905	8,372
Depreciation and amortization [1]	334,645	288,087	270,311
Impairments [1]	226,950	178,374	15,535
Other expense [1]	8,327	145	224
Less:			
Gain (loss) on divestiture and other, net	1,312	132,388	(14,641)
Equity income, net – affiliates	153,024	85,194	78,717
Interest income – affiliates	16,900	16,900	16,900
Other income [1]	2,592	1,283	524
Income tax benefit	355	39	—
Adjusted EBITDA	$1,205,761	$1,060,988	$1,028,208
Reconciliation of Net cash provided by operating activities to Adjusted EBITDA			
Net cash provided by operating activities	$1,020,634	$901,495	$917,585
Interest (income) expense, net	167,108	125,486	98,021
Uncontributed cash-based compensation awards	879	25	856
Accretion and amortization of long-term obligations, net	(5,142)	(4,254)	3,789
Current income tax (benefit) expense	480	2,408	5,817
Other (income) expense, net [2]	(3,017)	(1,299)	(479)
Distributions from equity investments in excess of cumulative earnings – affiliates	25,607	23,085	21,238
Changes in assets and liabilities:			
Accounts receivable, net	56,667	16,127	48,947
Accounts and imbalance payables and accrued liabilities, net	(30,722)	6,930	(58,359)
Other items, net	(13,873)	4,491	4,367
Adjusted EBITDA attributable to noncontrolling interest	(12,860)	(13,506)	(13,574)
Adjusted EBITDA	$1,205,761	$1,060,988	$1,028,208
Cash flow information of Western Gas Partners, LP			
Net cash provided by operating activities	$1,020,634	$901,495	$917,585
Net cash used in investing activities	(1,459,798)	(763,604)	(1,105,534)
Net cash provided by (used in) financing activities	450,798	(417,002)	447,841

(1) Includes our 75% share of depreciation and amortization; impairments; other expense; and other income attributable to the Chipeta complex.

(2) Excludes the non-cash loss on interest-rate swaps of $8.0 million for the year ended December 31, 2018. See Note 13—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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thousands except Coverage ratio	Year Ended December 31, 2018	2017	2016
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	$445,775	$567,483	$591,331
Add:			
Distributions from equity investments	169,906	110,465	103,423
Non-cash equity-based compensation expense	7,032	4,947	5,591
Non-cash settled interest expense, net [1]	—	71	(7,747)
Income tax (benefit) expense	2,946	4,866	8,372
Depreciation and amortization [2]	334,645	288,087	270,311
Impairments [2]	226,950	178,374	15,535
Above-market component of swap agreements with Anadarko [3]	51,618	58,551	45,820
Other expense [2]	8,327	145	224
Less:			
Recognized Service revenues – fee based (less than) in excess of customer billings [4]	14,581	—	—
Gain (loss) on divestiture and other, net	1,312	132,388	(14,641)
Equity income, net – affiliates	153,024	85,194	78,717
Cash paid for maintenance capital expenditures [2]	91,054	49,684	63,630
Capitalized interest	23,521	6,826	5,562
Cash paid for (reimbursement of) income taxes	2,408	1,194	838
Series A Preferred unit distributions	—	7,453	45,784
Other income [2]	2,592	1,283	524
Distributable cash flow	$958,707	$928,967	$852,446
Distributions declared [5]			
Limited partners – common units	$584,487		
General partner	327,363		
Total	$911,850		
Coverage ratio	1.05 x		

(1) Includes amounts related to the Deferred purchase price obligation - Anadarko. See Note 3—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; impairments; other expense; cash paid for maintenance capital expenditures; and other income attributable to the Chipeta complex.

(3) See Note 6—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

(4) 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.

(5) Reflects cash distributions of $3.830 per unit declared for the year ended December 31, 2018, including the cash distribution of $0.980 per unit paid on February 13, 2019, for the fourth-quarter 2018 distribution.

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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 NGLs prices. Crude oil, natural gas and NGLs 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, NGLs 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.

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. 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 significant inflation, which could materially increase our operating costs and capital expenditures and negatively impact our financial results. 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.

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Impact of interest rates. Overall, both short- and longer-term interest rates increased during 2018, yet remained low relative to historical averages. 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 four separate times during 2018. 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 over time. We may pursue certain asset acquisitions 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 on an economically accretive basis, 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.
Upon the consummation of the Merger, as discussed in Executive Summary–Merger transactions within this Item 7, we will acquire substantially all of Anadarko’s midstream assets.

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 5—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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RESULTS OF OPERATIONS

OPERATING RESULTS

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

	Year Ended December 31,		
thousands	2018	2017	2016
Total revenues and other (1)	$1,990,276	$2,248,356	$1,804,270
Equity income, net – affiliates	153,024	85,194	78,717
Total operating expenses (1)	1,515,219	1,788,549	1,176,408
Gain (loss) on divestiture and other, net	1,312	132,388	(14,641)
Proceeds from business interruption insurance claims (2)	—	29,882	16,270
Operating income (loss)	629,393	707,271	708,208
Interest income – affiliates	16,900	16,900	16,900
Interest expense	(184,008)	(142,386)	(114,921)
Other income (expense), net	(4,955)	1,299	479
Income (loss) before income taxes	457,330	583,084	610,666
Income tax (benefit) expense	2,946	4,866	8,372
Net income (loss)	454,384	578,218	602,294
Net income attributable to noncontrolling interest	8,609	10,735	10,963
Net income (loss) attributable to Western Gas Partners, LP	$445,775	$567,483	$591,331
Key performance metrics (3)			
Adjusted gross margin	$1,645,806	$1,376,478	$1,337,443
Adjusted EBITDA	1,205,761	1,060,988	1,028,208
Distributable cash flow	958,707	928,967	852,446

(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 Items Affecting the Comparability of Our Financial Results within this Item 7 and Note 6—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 How We Evaluate Our Operations 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, 2018” refer to the comparison of the year ended December 31, 2018, to the year ended December 31, 2017, and 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.

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Throughput

	Year Ended December 31,				
	2018	2017	Inc/ (Dec)	2016	Inc/ (Dec)
Throughput for natural gas assets (MMcf/d)					
Gathering, treating and transportation [(1)]	546	958	(43)%	1,537	(38)%
Processing [(1)]	3,205	2,563	25 %	2,350	9 %
Equity investment [(2)]	141	159	(11)%	177	(10)%
Total throughput for natural gas assets	3,892	3,680	6 %	4,064	(9)%
Throughput attributable to noncontrolling interest for natural gas assets	90	105	(14)%	124	(15)%
Total throughput attributable to Western Gas Partners, LP for natural gas assets	3,802	3,575	6 %	3,940	(9)%
Throughput for crude oil, NGLs and produced water assets (MBbls/d)					
Gathering, treating, transportation and disposal	146	71	106 %	57	25 %
Equity investment [(3)]	219	130	68 %	127	2 %
Total throughput for crude oil, NGLs and produced water assets	365	201	82 %	184	9 %

(1) The combination of the DBM complex and DBJV and Haley systems, effective January 1, 2018, into a single complex now referred to as the “West Texas complex” resulted in DBJV and Haley systems throughput previously reported as “Gathering, treating and transportation” now being reported as “Processing.”

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

(3) 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, 33.33% share of average FRP throughput and 20% share of average Whitethorn throughput.

Natural gas assets

Gathering, treating and transportation throughput decreased by 412 MMcf/d for the year ended December 31, 2018, primarily due to (i) the combination of the DBM complex and DBJV and Haley systems into a single complex now referred to as the “West Texas complex”, which resulted in DBJV and Haley systems throughput previously reported as “Gathering, treating and transportation” now being reported as “Processing” (decrease of 258 MMcf/d) and (ii) the divestiture of the Non-Operated Marcellus Interest as part of the Property Exchange in March 2017 (decrease of 158 MMcf/d).

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).

Processing throughput increased by 642 MMcf/d for the year ended December 31, 2018, primarily due to (i) the combination of the DBM complex and DBJV and Haley systems into the West Texas complex, (ii) increased production in the areas around the DJ Basin and West Texas complexes, (iii) the start-up of Train VI at the West Texas complex in December 2017, (iv) increased throughput at the West Texas complex due to the acquisition of the Additional DBJV System Interest as part of the Property Exchange in March 2017 and (v) increased throughput at the MGR assets due to downtime in 2017. These increases were partially offset by lower throughput at the Chipeta complex due to downstream fractionation capacity constraints in the third quarter of 2018 and the expiration and non-renewal of a contract in September 2017.

Processing throughput increased by 213 MMcf/d for the year ended December 31, 2017, primarily due to the incident at the DBM complex in 2015, 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.

Equity investment throughput decreased by 18 MMcf/d for the year ended December 31, 2018, primarily due to decreased throughput at the Fort Union and Rendezvous systems due to production declines in the area, as well as throughput being diverted from the Fort Union system to other nearby systems.

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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.

Crude oil, NGLs and produced water assets

Gathering, treating, transportation and disposal throughput increased by 75 MBbls/d for the year ended December 31, 2018, primarily due to increased throughput from the DBM water systems, which commenced operation during the second quarter of 2017.
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 89 MBbls/d for the year ended December 31, 2018, primarily due to (i) the acquisition of the interest in Whitethorn in June 2018 and (ii) increased volumes on TEP and FRP as a result of increased NGLs production in the DJ Basin 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 NGLs 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.

Service Revenues

	Year Ended December 31,				
thousands except percentages	2018	2017	Inc/ (Dec)	2016	Inc/ (Dec)
Service revenues – fee based	$1,609,245	$1,237,949	30 %	$1,227,849	1 %
Service revenues – product based	85,553	—	NM	—	NM
Total service revenues	$1,694,798	$1,237,949	37 %	$1,227,849	1 %

NM-Not Meaningful

Service revenues – fee based increased by $371.3 million for the year ended December 31, 2018, primarily due to increases of (i) $141.4 million at the West Texas complex due to increased throughput, (ii) $124.1 million at the DJ Basin complex due to increased throughput ($100.5 million) and a higher processing fee ($23.6 million) due to a new contract effective August 2017, (iii) $109.8 million from the adoption of Topic 606 as discussed under Items Affecting the Comparability of Our Financial Results within this Item 7, and (iv) $25.2 million at the DBM water systems, which commenced operation during the second quarter of 2017. These increases were partially offset by decreases of (i) $22.1 million due to the divestiture of the Non-Operated Marcellus Interest as part of the Property Exchange in March 2017 and (ii) $10.4 million at the Springfield system due to a lower cost of service rate.
Service revenues – fee based 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.
Service revenues – product based increased by $85.6 million for the year ended December 31, 2018, due to the adoption of Topic 606 as discussed under Items Affecting the Comparability of Our Financial Results within this

Item 7. Under Topic 606, certain of our customer agreements result in revenues being recognized when the natural gas and/or NGLs are received from the customer as noncash consideration for the services provided. In addition, retained proceeds from sales of customer products where we are acting as their agent are included in Service revenues – product based.

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Product Sales

thousands except percentages and per-unit amounts	Year Ended December 31, 2018	2017	Inc/ (Dec)	2016	Inc/ (Dec)
Natural gas sales [(1)]	$84,572	$382,303	(78)%	$230,366	66 %
NGLs sales [(1)]	209,420	607,630	(66)%	341,947	78 %
Total Product sales	$293,992	$989,933	(70)%	$572,313	73 %
Gross average sales price per unit [(1)]:					
Natural gas (per Mcf)	$2.15	$2.92	(26)%	$2.51	16 %
NGLs (per Bbl)	30.87	23.24	33 %	19.96	16 %

(1) Includes the effects of commodity price swap agreements for the MGR assets, DJ Basin complex and Hugoton system (until its divestiture in October 2016), excluding the amounts considered above market with respect to these swap agreements that were recorded as capital contributions in the consolidated statements of equity and partners' capital. See Note 6—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Natural gas sales decreased by $297.7 million for the year ended December 31, 2018, primarily due to decreases of (i) $245.2 million from the adoption of Topic 606 as discussed under Items Affecting the Comparability of Our Financial Results within this Item 7, (ii) $24.4 million at the West Texas complex due to a decrease in average price, partially offset by an increase in volumes sold, (iii) $5.7 million due to a decrease in average price and $9.3 million due to the shutdown of the Kitty Draw gathering system, both at the Hilight system (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), and (iv) $6.9 million at the DJ Basin complex due to a decrease in the swap market price, partially offset by an increase in bypass volumes.

Natural gas sales increased by $151.9 million for the year ended December 31, 2017, 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.

NGLs sales decreased by $398.2 million for the year ended December 31, 2018, primarily due to a decrease of $767.3 million from the adoption of Topic 606 as discussed under Items Affecting the Comparability of Our Financial Results within this Item 7. This decrease was partially offset by increases of (i) $256.8 million at the West Texas complex due to an increase in volumes sold, partially offset by a decrease in average price, (ii) $57.9 million at the DJ Basin complex due to an increase in the swap market price and volumes sold, (iii) $23.8 million at the Brasada complex due to volumes sold under a new sales agreement beginning January 1, 2018, and (iv) $9.0 million at the DBM water systems, which commenced operation during the second quarter of 2017.

NGLs sales increased by $265.7 million for the year ended December 31, 2017, 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.

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Other Revenues

	Year Ended December 31,				
thousands except percentages	2018	2017	Inc/ (Dec)	2016	Inc/ (Dec)
Other revenues	$1,486	$20,474	(93)%	$4,108	NM

For the year ended December 31, 2018, Other revenues decreased by $19.0 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. Upon adoption of Topic 606 on January 1, 2018, deficiency fees are recorded as Service revenues – fee based in the consolidated statements of operations (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 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

	Year Ended December 31,				
thousands except percentages	2018	2017	Inc/ (Dec)	2016	Inc/ (Dec)
Equity income, net – affiliates	$153,024	$85,194	80 %	$78,717	8 %

For the year ended December 31, 2018, Equity income, net – affiliates increased by $67.8 million, primarily due to (i) the acquisition of the interest in Whitethorn in June 2018 and (ii) increased volumes at the TEFR Interests. These increases were partially offset by a decrease in volumes at the Fort Union system.
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.

Cost of Product and Operation and Maintenance Expenses

	Year Ended December 31,				
thousands except percentages	2018	2017	Inc/ (Dec)	2016	Inc/ (Dec)
NGLs purchases (1)	$300,411	$527,298	(43)%	$238,660	121%
Residue purchases (1)	100,780	357,395	(72)%	231,722	54 %
Other	30,730	24,000	28 %	23,812	1 %
Cost of product	431,921	908,693	(52)%	494,194	84 %
Operation and maintenance	414,784	315,994	31 %	308,010	3 %
Total Cost of product and Operation and maintenance expenses	$846,705	$1,224,687	(31)%	$802,204	53 %

(1) For the years ended December 31, 2017 and 2016, includes the effects of commodity price swap agreements for the MGR assets, DJ Basin complex and Hugoton system (until its divestiture in October 2016), excluding the amounts considered above market with respect to these swap agreements that were recorded as capital contributions in the consolidated statements of equity and partners' capital. See Note 6—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 decreased by $226.9 million for the year ended December 31, 2018, primarily due to a decrease of $598.6 million from the adoption of Topic 606 as discussed under Items Affecting the Comparability of Our Financial Results within this Item 7, partially offset by increases of (i) $269.5 million at the West Texas complex due to an increase in volumes purchased, (ii) $56.0 million at the DJ Basin complex due to an increase in average price and volumes purchased, (iii) $22.0 million at the Brasada complex due to volumes purchased under a new purchase agreement beginning January 1, 2018, and (iv) $8.8 million at the DBM water systems, which commenced operation during the second quarter of 2017.

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.

Residue purchases decreased by $256.6 million for the year ended December 31, 2018, primarily due to decreases of (i) $230.5 million from the adoption of Topic 606 as discussed under Items Affecting the Comparability of Our Financial Results within this Item 7, (ii) $14.1 million at the West Texas complex due to a decrease in average price, partially offset by an increase in volumes purchased, (iii) $6.8 million at the MGR assets due to a decrease in average price and volumes purchased, and (iv) $5.0 million at the Hilight system due to a decrease in volumes purchased.

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.

Other items increased by $6.7 million for the year ended December 31, 2018, primarily due to an increase of $20.9 million at the DJ Basin complex due to changes in affiliate contract terms in August 2017, partially offset by decreases of (i) $9.8 million from the adoption of Topic 606 as discussed under Items Affecting the Comparability of Our Financial Results within this Item 7 and (ii) $7.3 million from changes in imbalance positions primarily at the West Texas complex.

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 incident at the DBM complex in 2015 and (ii) changes in imbalance positions.

Operation and maintenance expense increased by $98.8 million for the year ended December 31, 2018, primarily due to increases of (i) $62.2 million at the West Texas complex due to increases in salaries and wages, surface maintenance and plant repairs, utilities expense, and equipment rentals, (ii) $23.7 million at the DJ Basin complex due to increases in utilities expense, surface maintenance and plant repairs, and salaries and wages, and (iii) $8.8 million at the DBM water systems, which commenced operation during the second quarter of 2017.

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.

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Other Operating Expenses

	Year Ended December 31,				
thousands except percentages	2018	2017	Inc/ (Dec)	2016	Inc/ (Dec)
General and administrative	$59,706	$47,796	25 %	$45,591	5 %
Property and other taxes	42,934	46,818	(8)%	40,145	17 %
Depreciation and amortization	337,536	290,874	16 %	272,933	7 %
Impairments	228,338	178,374	28 %	15,535	NM
Total other operating expenses	$668,514	$563,862	19 %	$374,204	51 %

General and administrative expenses increased by $11.9 million for the year ended December 31, 2018, primarily due to (i) legal and consulting fees incurred in 2018 and (ii) personnel costs for which we reimbursed Anadarko pursuant to our omnibus agreement. These increases were partially offset by a decrease in bad debt expense.

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.

Property and other taxes decreased by $3.9 million for the year ended December 31, 2018, primarily due to ad valorem tax decreases of $5.7 million at the DJ Basin complex caused by revisions in estimated tax liabilities, offset by increases of $2.5 million at the West Texas complex.

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.

Depreciation and amortization expense increased by $46.7 million for the year ended December 31, 2018, primarily due to increases of $30.4 million at the West Texas complex due to capital projects being placed into service and $17.1 million at the DJ Basin complex related to the shutdown of the Third Creek gathering system (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).

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.

Impairment expense for the year ended December 31, 2018, was primarily due to impairments of (i) $125.9 million at the Third Creek gathering system and $8.1 million at the Kitty Draw gathering system (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), (ii) $38.7 million at the Hilight system, (iii) $34.6 million at the MIGC system, (iv) $10.9 million at the GNB NGL pipeline and (v) $5.6 million at the Chipeta complex.

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.

For further information on impairment expense for the periods presented, see Note 8—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	2018	2017	Inc/ (Dec)	2016	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	$(199,322)	$(142,525)	40 %	$(121,832)	17 %
Amortization of debt issuance costs and commitment fees	(8,207)	(6,616)	24 %	(6,398)	3 %
Capitalized interest	23,521	6,826	NM	5,562	23 %
Affiliates					
Deferred purchase price obligation – Anadarko[1]	—	(71)	(100)%	7,747	(101)%
Interest expense	$(184,008)	$(142,386)	29 %	$(114,921)	24 %

(1) See Note 3—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 $41.6 million for the year ended December 31, 2018, primarily due to (i) $46.3 million of interest incurred on the 4.500% Senior Notes due 2028 and 5.300% Senior Notes due 2048 that were issued in March 2018 and (ii) $15.3 million of interest incurred on the 4.750% Senior Notes due 2028 and 5.500% Senior Notes due 2048 that were issued in August 2018. These increases were partially offset by an increase in capitalized interest of $16.7 million, primarily due to continued construction and expansion at (i) the DJ Basin complex, including construction of the Latham processing plant beginning in 2018, and (ii) the West Texas complex, including construction of the Mentone processing plant beginning in the fourth quarter of 2017.

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 3—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 4.650% Senior Notes due 2026 issued in July 2016 and (iii) $8.7 million of interest incurred on the additional 5.450% Senior Notes due 2044 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.

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Other Income (Expense), Net

	Year Ended December 31,				
thousands except percentages	2018	2017	Inc/ (Dec)	2016	Inc/ (Dec)
Other income (expense), net	$(4,955)	$1,299	NM	$479	171%

Other income (expense), net decreased by $6.3 million for the year ended December 31, 2018, primarily due to a non-cash loss of $8.0 million on interest-rate swaps entered into in December 2018. See Note 13—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for additional information.

Income Tax (Benefit) Expense

	Year Ended December 31,				
thousands except percentages	2018	2017	Inc/ (Dec)	2016	Inc/ (Dec)
Income (loss) before income taxes	$457,330	$583,084	(22)%	$610,666	(5)%
Income tax (benefit) expense	2,946	4,866	(39)%	8,372	(42)%
Effective tax rate	1 %	1 %		1 %	

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 years ended December 31, 2018 and 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 year ended December 31, 2016, 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. Income attributable to the Springfield system prior to and including February 2016 was subject to federal and state income tax. Income earned on the Springfield system for periods subsequent to February 2016 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	2018	2017	Inc/ (Dec)	2016	Inc/ (Dec)
Adjusted gross margin for natural gas assets (1)	$1,398,953	$1,222,632	14 %	$1,194,877	2 %
Adjusted gross margin for crude oil, NGLs and produced water assets (2)	246,853	153,846	60 %	142,566	8 %
Adjusted gross margin (3)	1,645,806	1,376,478	20 %	1,337,443	3 %
Adjusted gross margin per Mcf for natural gas assets (4)	1.01	0.94	7 %	0.83	13 %
Adjusted gross margin per Bbl for crude oil, NGLs and produced water assets (5)	1.85	2.10	(12)%	2.11	— %
Adjusted EBITDA (3)	1,205,761	1,060,988	14 %	1,028,208	3 %
Distributable cash flow (3)	958,707	928,967	3 %	852,446	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), less 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, NGLs and produced water assets is calculated as total revenues and other for crude oil, NGLs and produced water assets (less reimbursements for electricity-related expenses recorded as revenue), less cost of product for crude oil, NGLs and produced water assets, and plus distributions from our equity investments in White Cliffs, the Mont Belvieu JV, the TEFR Interests and Whitethorn. See the reconciliation of Adjusted gross margin for crude oil, NGLs 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, NGLs and produced water assets, divided by total throughput (MBbls/d) for crude oil, NGLs and produced water assets.

Adjusted gross margin. Adjusted gross margin increased by $269.3 million for the year ended December 31, 2018, primarily due to (i) increased throughput at the West Texas complex, (ii) increased throughput and a higher processing fee at the DJ Basin complex, (iii) the acquisition of the interest in Whitethorn in June 2018, (iv) the start-up of the DBM water systems during the second quarter of 2017, (v) the Property Exchange in March 2017, and (vi) a cost of service rate adjustment at the Springfield system in the fourth quarter of 2018 (see Revenue from contracts with customers (Topic 606) under Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K). These increases were partially offset by a decrease due to the shutdown of the Kitty Draw gathering system (part of the Hilight system) in 2018 (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).

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 per Mcf for natural gas assets increased by $0.07 for the year ended December 31, 2018, primarily due to (i) increased throughput at the West Texas complex, which has a higher-than-average margin as compared to our other natural gas assets, (ii) the Property Exchange in March 2017, and (iii) a cost of service rate adjustment at the Springfield gas gathering system in the fourth quarter of 2018.

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

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Adjusted gross margin per Bbl for crude oil, NGLs and produced water assets decreased by $0.25 for the year ended December 31, 2018, primarily due to increased throughput at the DBM water systems and the acquisition of the interest in Whitethorn in June 2018, which have lower margins per Bbl than our other crude oil and NGLs assets. These decreases were partially offset by (i) higher distributions received from the TEFR Interests and the Mont Belvieu JV and (ii) a cost of service rate adjustment at the Springfield oil gathering system in the fourth quarter of 2018.
Adjusted gross margin per Bbl for crude oil, NGLs 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 EBITDA. Adjusted EBITDA increased by $144.8 million for the year ended December 31, 2018, primarily due to (i) a $477.4 million decrease in cost of product (net of lower of cost or market inventory adjustments) and (ii) a $59.4 million increase in distributions from equity investments. These amounts were partially offset by (i) a $258.1 million decrease in total revenues and other, (ii) a $98.8 million increase in operation and maintenance expenses, (iii) a $29.9 million decrease in business interruption proceeds, and (iv) a $9.8 million increase in general and administrative expenses excluding non-cash equity-based compensation expense.
Adjusted EBITDA increased by $32.8 million for the year ended December 31, 2017, primarily due to (i) a $444.1 million increase in total revenues and other, (ii) a $13.6 million increase in business interruption proceeds, and (iii) a $7.0 million increase in distributions from equity investments. These amounts were partially offset by (i) a $414.5 million increase in cost of product (net of lower of cost or market inventory adjustments), (ii) an $8.0 million increase in operation and maintenance expenses, (iii) a $6.7 million increase in property and other tax expense, and (iv) a $2.8 million increase in general and administrative expenses excluding non-cash equity-based compensation expense.

Distributable cash flow. Distributable cash flow increased by $29.7 million for the year ended December 31, 2018, primarily due to (i) a $144.8 million increase in Adjusted EBITDA and (ii) a $7.5 million decrease in Series A Preferred unit distributions. These amounts were partially offset by (i) a $58.4 million increase in net cash paid for interest expense, (ii) a $41.4 million increase in cash paid for maintenance capital expenditures, (iii) $14.6 million of customer billings less than the amount recognized as Service revenues – fee based, and (iv) a $6.9 million decrease in the above-market component of the swap agreements with Anadarko.
Distributable cash flow increased by $76.5 million for the year ended December 31, 2017, primarily due to (i) a $38.3 million decrease in Series A Preferred unit distributions, (ii) a $32.8 million increase in Adjusted EBITDA, (iii) a $13.9 million decrease in cash paid for maintenance capital expenditures, and (iv) 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.

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, 2018, 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 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.

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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 2018 of $0.980 per unit, or $234.8 million in aggregate, including incentive distributions, but excluding distributions on Class C units. The cash distribution was paid on February 13, 2019, to unitholders of record at the close of business on February 1, 2019. 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 the earlier of (i) the consummation of the Merger or (ii) March 1, 2020, unless we elect to convert such units earlier or Anadarko extends the conversion date (see Note 5—Equity and Partners' Capital 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 $14.1 million for the fourth quarter of 2018.
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, 2018, we had a $174.1 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, 2018, was primarily due to (i) the costs incurred related to continued construction and expansion at the West Texas and DJ Basin complexes and (ii) system shutdowns at the Kitty Draw gathering system (part of the Hilight system) and Third Creek gathering system (part of the DJ Basin complex). See Note 1—Summary of Significant Accounting Policies and Note 11—Components of Working Capital in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K. As of December 31, 2018, we had $1.3 billion available for borrowing under the RCF. See Note 13—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	2018	2017	2016
Acquisitions	$162,112	$159,208	$716,465
Expansion capital expenditures	$1,102,766	$623,674	$410,221
Maintenance capital expenditures	91,130	49,964	63,637
Total capital expenditures (1) (2)	$1,193,896	$673,638	$473,858
Capital incurred (2)	$1,185,682	$798,694	$491,349

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

(2) For the years ended December 31, 2018, 2017 and 2016, included $22.1 million, $6.8 million and $5.6 million, respectively, of capitalized interest.

Acquisitions during 2018 included a 20% interest in Whitethorn, a 15% interest in Cactus II and equipment purchases from Anadarko. Acquisitions during 2017 included the Additional DBJV System Interest and equipment purchases from Anadarko. Acquisitions during 2016 included Springfield and equipment purchases from Anadarko. See Note 3—Acquisitions and Divestitures and Note 6—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 $520.3 million for the year ended December 31, 2018. Expansion capital expenditures increased by $479.1 million (including a $15.3 million increase in capitalized interest) for the year ended December 31, 2018, primarily due to increases of $271.7 million at the West Texas complex and $216.2 million at the DJ Basin complex, primarily due to pipe, compression and processing projects. These increases were partially offset by a decrease of $12.8 million at the DBM water systems, which commenced operation during the second quarter of 2017. Maintenance capital expenditures increased by $41.2 million for the year ended December 31, 2018, primarily due to increases at the DJ Basin and West Texas complexes.

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 incident in 2015. These decreases were partially offset by increases at the Hilight and Haley systems.

For the year ending December 31, 2019, we estimate that our total capital expenditures will be between $1.3 billion to $1.4 billion (excluding acquisitions and including our 75% share of Chipeta's capital expenditures, equity investments and the 30% interest in Red Bluff Express Pipeline, LLC we closed on in January 2019) and our maintenance capital expenditures will be between $110 million to $120 million.

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	2018	2017	2016
Net cash provided by (used in):			
Operating activities	$1,020,634	$901,495	$917,585
Investing activities	(1,459,798)	(763,604)	(1,105,534)
Financing activities	450,798	(417,002)	447,841
Net increase (decrease) in cash and cash equivalents	$11,634	$(279,111)	$259,892

Operating Activities. Net cash provided by operating activities increased for the year ended December 31, 2018, primarily due to the impact of changes in working capital items and increases in distributions from equity investments. Net cash provided by operating activities decreased for the year ended December 31, 2017, 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, 2018, included the following:

- $1.2 billion of capital expenditures, primarily related to construction and expansion at the West Texas and DJ Basin complexes;
- $161.9 million of cash paid for the acquisitions of the interests in Whitethorn and Cactus II;
- $133.3 million of capital contributions paid to Cactus II, the TEFR Interests, Whitethorn and White Cliffs for construction activities; and
- $25.6 million of distributions received from equity investments in excess of cumulative earnings.

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 received from equity investments in excess of cumulative earnings;
- $23.0 million of proceeds from property insurance claims attributable to the incident at the DBM complex in 2015; 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;

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- $45.1 million of net proceeds from the sale of the Hugoton system in Southwest Kansas and Oklahoma;
- $21.2 million of distributions received from equity investments in excess of cumulative earnings;
- $17.5 million of proceeds from property insurance claims attributable to the incident at the DBM complex in 2015; and
- $4.0 million of cash paid for equipment purchases from Anadarko.

Financing Activities. Net cash provided by financing activities for the year ended December 31, 2018, included the following:

- $1.08 billion of net proceeds from the offering of the 4.500% Senior Notes due 2028 and 5.300% Senior Notes due 2048 in March 2018, after underwriting and original issue discounts and offering costs, which were used to repay amounts outstanding under the RCF and for general partnership purposes, including to fund capital expenditures;
- $893.6 million of distributions paid to our unitholders;
- $738.1 million of net proceeds from the offering of the 4.750% Senior Notes due 2028 and 5.500% Senior Notes due 2048 in August 2018, after underwriting and original issue discounts and offering costs, which were used to repay the maturing 2.600% Senior Notes due August 2018, repay amounts outstanding under the RCF and for general partnership purposes, including to fund capital expenditures;
- $690.0 million of repayments of outstanding borrowings under the RCF;
- $534.2 million of borrowings under the RCF, net of extension and amendment costs, which were used for general partnership purposes, including to fund capital expenditures;
- $350.0 million of principal repayment on the maturing 2.600% Senior Notes due August 2018;
- $51.6 million of capital contributions from Anadarko related to the above-market component of swap agreements;
- $13.5 million of distributions paid to the noncontrolling interest owner of Chipeta; and
- $3.4 million of issuance costs incurred in connection with the 364-day Facility.

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.

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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 offering of the 4.650% Senior Notes due 2026 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 5.450% Senior Notes due 2044 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;
- $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.

Debt and credit facilities. As of December 31, 2018, the carrying value of our outstanding debt was $4.8 billion. See Note 13—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Senior Notes. In August 2018, the 4.750% Senior Notes due 2028 and 5.500% Senior Notes due 2048 were offered to the public at prices of 99.818% and 98.912%, respectively, of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rates of the senior notes are 4.885% and 5.652%, respectively. Interest is paid on each such series semi-annually on February 15 and August 15 of each year, beginning February 15, 2019. The net proceeds were used to repay the maturing 2.600% Senior Notes due August 2018, repay amounts outstanding under the RCF and for general partnership purposes, including to fund capital expenditures.
In March 2018, the 4.500% Senior Notes due 2028 and 5.300% Senior Notes due 2048 were offered to the public at prices of 99.435% and 99.169%, respectively, of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rates of the senior notes are 4.682% and 5.431%, respectively. Interest is paid on each such series semi-annually on March 1 and September 1 of each year, beginning September 1, 2018. The net proceeds were used to repay amounts outstanding under the RCF and for general partnership purposes, including to fund capital expenditures.

At December 31, 2018, we were in compliance with all covenants under the indentures governing our outstanding notes.

Revolving credit facility. In February 2018, we entered into the five-year $1.5 billion RCF by amending and restating the $1.2 billion credit facility that was originally entered into in February 2014. The RCF is expandable to a maximum of $2.0 billion, matures in February 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 our senior unsecured debt rating. We are 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 our senior unsecured debt rating.

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.

As of December 31, 2018, we had $220.0 million in outstanding borrowings and $4.6 million in outstanding letters of credit, resulting in $1.3 billion available for borrowing under the RCF. At December 31, 2018, the interest rate on the RCF was 3.74% and the facility fee rate was 0.20%. At December 31, 2018, we were in compliance with all covenants under the RCF.

In December 2018, we entered into an amendment to the RCF for (i) subject to the consummation of the Merger (see Executive Summary–Merger transactions within this Item 7), an increase to the size of the RCF to $2.0 billion, while leaving the $0.5 billion accordion feature of the RCF unexercised, and (ii) effective on February 15, 2019, the exercise of one of our one-year extension options to extend the maturity date of the RCF to February 2024.

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.

364-day Facility. In December 2018, we entered into the $2.0 billion 364-day Facility, the proceeds of which will be used to fund substantially all of the cash portion of the consideration under the Merger Agreement and the payment of related transaction costs (see Executive Summary–Merger transactions within this Item 7). The 364-day Facility will mature on the day prior to the one-year anniversary of the completion of the Merger, and will bear interest at LIBOR, plus applicable margins ranging from 1.000% to 1.625%, 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 as defined in the 364-day Facility and plus applicable margins currently ranging from zero to 0.625%, based upon our senior unsecured debt rating. We are also required to pay a ticking fee of 0.175% on the commitment amount beginning 90 days after the effective date of the credit agreement through the date of funding under the 364-day Facility.

Funding of the 364-day Facility is conditioned upon the consummation of the Merger and net cash proceeds received from future asset sales and debt or equity offerings by us must be used to repay amounts outstanding under the facility. The 364-day Facility contains covenants and customary events of default that are substantially similar to those contained in the RCF.

Interest-rate swaps. In December 2018, we entered into interest-rate swap agreements with an aggregate notional amount of $750.0 million to manage interest rate risk associated with anticipated 2019 debt issuances. Pursuant to these swap agreements, we exchanged a floating interest rate indexed to the three-month LIBOR for a fixed interest rate. Depending on market conditions, liability management actions or other factors, we may settle or amend certain or all of the currently outstanding interest-rate swaps.

We do not apply hedge accounting and, therefore, gains and losses associated with the interest-rate swaps are recognized currently in earnings. For the year ended December 31, 2018, we recognized a non-cash loss of $8.0

million, which is included in Other income (expense), net in the consolidated statements of operations. The fair value of the interest-rate swaps as of December 31, 2018, was an $8.0 million liability, which is reported in Accrued liabilities on the consolidated balance sheets. See Note 13—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for additional information.

DBJV acquisition - 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. 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.

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, 2018, we had issued no common units under the registration statement associated with the $500.0 million COP. Upon the consummation of the Merger (see Executive Summary–Merger transactions within this Item 7), we will terminate the registration statement relating to the $500.0 million COP and, therefore, common units will no longer be available for issuance thereunder.

Credit risk. We bear credit risk through 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. See Note 6—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 NGLs purchase agreements, Anadarko’s note payable to us, our omnibus agreement, the services and secondment agreement, or the contribution agreements.

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CONTRACTUAL OBLIGATIONS

The following is a summary of our contractual cash obligations as of December 31, 2018. 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 2019.

	Obligations by Period						
thousands	2019	2020	2021	2022	2023	Thereafter	Total
Long-term debt							
Principal	$—	$—	$500,000	$670,000	$220,000	$3,450,000	$4,840,000
Interest	231,068	231,068	214,420	204,019	170,079	2,303,819	3,354,473
Asset retirement obligations	25,938	28,111	6,297	—	—	225,568	285,914
Capital expenditures	85,346	—	—	—	—	—	85,346
Credit facility fees	3,100	3,100	3,100	3,100	396	—	12,796
Environmental obligations	863	292	291	109	110	—	1,665
Operating leases	8,711	2,236	460	467	473	1,547	13,894
Total	$355,026	$264,807	$724,568	$877,695	$391,058	$5,980,934	$8,594,088

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 12—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 14—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 13—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 14—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 14—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 6—Transactions with Affiliates and Note 14—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, revenues and fair values. On an annual basis, as determined by the specific agreement, management reviews and updates certain gathering rates that are based on cost of service agreements. These cost of service gathering rates are calculated using a contractually specified rate of return and estimates including long-term assumptions for capital invested, receipt volumes, and operating and maintenance expenses, among others. See Contract balances in Note 2—Revenue from Contracts with Customers in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K. 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 8—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, 2018, 2017 and 2016.

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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, (iv) for the initial measurement of asset retirement obligations, (v) for the initial measurement of environmental obligations assumed in a third-party acquisition and (vi) of interest-rate swaps. 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 10-K.

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 14—Commitments and Contingencies and Note 13—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.

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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 because 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.

For the year ended December 31, 2018, 89% of our wellhead natural gas volumes (excluding equity investments) and 100% of our crude oil and produced water throughput (excluding equity investments) were attributable to fee-based contracts. A 10% increase or decrease in commodity prices would not 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 and four times during 2018. 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, 2018, we had $220.0 million in outstanding borrowings under the RCF (which bears interest at a rate based on LIBOR or, at our option, an alternative base rate). While a 10% change in the applicable benchmark interest rate would not materially impact interest expense on outstanding borrowings under the RCF, it would impact the fair value of the Senior Notes at December 31, 2018.

In December 2018, we entered into interest-rate swap agreements to manage interest rate risk associated with anticipated 2019 debt issuances. At December 31, 2018, we had a net derivative liability position of $8.0 million related to interest-rate swaps. A 10% increase or decrease in the LIBOR interest rate curve would change the aggregate fair value of outstanding interest-rate swap agreements by $23.2 million. However, any change in the interest rate derivative gain or loss could be substantially offset by changes in actual borrowing costs associated with anticipated 2019 debt issuances. See Note 13—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

We may incur additional variable-rate debt in the future, either under the RCF, the 364-day Facility 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

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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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, 2018. 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, 2018.

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, 2018.

/s/ Robin H. Fielder
Robin H. Fielder
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 20, 2019

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WESTERN GAS PARTNERS, LP

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To 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, 2018, 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, 2018, 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, 2018 and 2017, 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, 2018, and the related notes (collectively, the consolidated financial statements), and our report dated February 20, 2019 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Partnership'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 20, 2019

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WESTERN GAS PARTNERS, LP

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Unitholders
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, 2018 and 2017, 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, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2018, 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, 2018, 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 20, 2019 expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

Change in Accounting Principle

As discussed in Note 1 to the consolidated financial statements, the Partnership has changed its method of accounting for revenue recognition in 2018 due to the adoption of Accounting Standards Codification Topic 606 Revenue from Contracts with Customers.

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 20, 2019

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WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
thousands except per-unit amounts	2018	2017	2016
Revenues and other – affiliates			
Service revenues – fee based	$793,594	$656,795	$750,087
Service revenues – product based	2,248	—	—
Product sales	272,018	692,447	478,145
Other	—	16,076	—
Total revenues and other – affiliates	1,067,860	1,365,318	1,228,232
Revenues and other – third parties			
Service revenues – fee based	815,651	581,154	477,762
Service revenues – product based	83,305	—	—
Product sales	21,974	297,486	94,168
Other	1,486	4,398	4,108
Total revenues and other – third parties	922,416	883,038	576,038
Total revenues and other	1,990,276	2,248,356	1,804,270
Equity income, net – affiliates	153,024	85,194	78,717
Operating expenses			
Cost of product [(1)]	431,921	908,693	494,194
Operation and maintenance [(1)]	414,784	315,994	308,010
General and administrative [(1)]	59,706	47,796	45,591
Property and other taxes	42,934	46,818	40,145
Depreciation and amortization	337,536	290,874	272,933
Impairments	228,338	178,374	15,535
Total operating expenses	1,515,219	1,788,549	1,176,408
Gain (loss) on divestiture and other, net [(2)]	1,312	132,388	(14,641)
Proceeds from business interruption insurance claims	—	29,882	16,270
Operating income (loss)	629,393	707,271	708,208
Interest income – affiliates	16,900	16,900	16,900
Interest expense [(3)]	(184,008)	(142,386)	(114,921)
Other income (expense), net	(4,955)	1,299	479
Income (loss) before income taxes	457,330	583,084	610,666
Income tax expense (benefit)	2,946	4,866	8,372
Net income (loss)	454,384	578,218	602,294
Net income attributable to noncontrolling interest	8,609	10,735	10,963
Net income (loss) attributable to Western Gas Partners, LP	$445,775	$567,483	$591,331
Limited partners' interest in net income (loss):			
Net income (loss) attributable to Western Gas Partners, LP	$445,775	$567,483	$591,331
Pre-acquisition net (income) loss allocated to Anadarko	—	—	(11,326)
Series A Preferred units interest in net (income) loss [(4)]	—	(42,373)	(76,893)
General partner interest in net (income) loss [(4)]	(346,538)	(303,835)	(236,561)
Common and Class C limited partners' interest in net income (loss) [(4)]	99,237	221,275	266,551
Net income (loss) per common unit – basic and diluted [(4)]	$0.55	$1.30	$1.74

(1) Cost of product includes product purchases from affiliates (as defined in Note 1) of $193.7 million, $86.0 million and $80.5 million for the years ended December 31, 2018, 2017 and 2016, respectively. Operation and maintenance includes charges from affiliates of $98.8 million, $72.5 million and $72.3 million for the years ended

December 31, 2018, 2017 and 2016, respectively. General and administrative includes charges from affiliates of $45.4 million, $39.1 million and $38.1 million for the years ended December 31, 2018, 2017 and 2016, respectively. See Note 6.

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

(3) Includes affiliate (as defined in Note 1) amounts of zero, $(0.1) million and $7.7 million for the years ended December 31, 2018, 2017 and 2016, respectively. See Note 3 and Note 13.

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

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

	December 31,	
thousands except number of units	2018	2017
ASSETS		
Current assets		
Cash and cash equivalents	$90,448	$78,814
Accounts receivable, net (1)	217,101	160,432
Other current assets (2)	25,914	14,816
Total current assets	333,463	254,062
Note receivable – Anadarko	260,000	260,000
Property, plant and equipment		
Cost	9,250,228	7,864,535
Less accumulated depreciation	2,638,155	2,133,644
Net property, plant and equipment	6,612,073	5,730,891
Goodwill	416,160	416,160
Other intangible assets	746,804	775,269
Equity investments	845,279	566,211
Other assets	22,503	11,757
Total assets	$9,236,282	$8,014,350
LIABILITIES, EQUITY AND PARTNERS' CAPITAL		
Current liabilities		
Accounts and imbalance payables	$350,325	$349,801
Accrued ad valorem taxes	29,336	26,633
Accrued liabilities (3)	127,921	47,899
Total current liabilities	507,582	424,333
Long-term liabilities		
Long-term debt	4,787,381	3,464,712
Deferred income taxes	9,697	7,409
Asset retirement obligations	259,976	143,394
Other liabilities (4)	140,067	3,491
Total long-term liabilities	5,197,121	3,619,006
Total liabilities	5,704,703	4,043,339
Equity and partners' capital		
Common units (152,609,285 and 152,602,105 units issued and outstanding at December 31, 2018 and 2017, respectively)	2,475,540	2,950,010
Class C units (14,372,665 and 13,243,883 units issued and outstanding at December 31, 2018 and 2017, respectively) (5)	791,410	780,040
General partner units (2,583,068 units issued and outstanding at December 31, 2018 and 2017)	206,862	179,232
Total partners' capital	3,473,812	3,909,282
Noncontrolling interest	57,767	61,729
Total equity and partners' capital	3,531,579	3,971,011
Total liabilities, equity and partners' capital	$9,236,282	$8,014,350

(1) Accounts receivable, net includes amounts receivable from affiliates (as defined in Note 1) of $72.8 million and $36.3 million as of December 31, 2018 and 2017, respectively.

(2) Other current assets includes affiliate amounts of $3.7 million and zero as of December 31, 2018 and 2017, respectively.

(3) Accrued liabilities includes affiliate amounts of $2.4 million and $0.2 million as of December 31, 2018 and 2017, respectively.

(4) Other liabilities includes affiliate amounts of $55.7 million and $0.7 million as of December 31, 2018 and 2017, respectively.

(5) All outstanding Class C units will convert into the Partnership's common units on a one-for-one basis immediately prior to the closing of the Merger (as defined in Note 1), if consummated. If the Merger is not consummated, the conversion will occur on March 1, 2020, unless the Partnership elects to convert such units earlier or Anadarko extends the conversion date. See Note 1 and Note 5.

See accompanying Notes to Consolidated Financial Statements.

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

thousands	Partners' Capital Net Investment by Anadarko	Common Units	Class C Units	Series A Preferred Units	General Partner Units	Noncontrolling Interest	Total
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 units	—	(42,407)	11,298	31,109	—	—	—
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
	—	686,936	—	(686,936)	—	—	—

Conversion of Series A Preferred units into common units [3]							
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
Balance at December 31, 2017	$—	$2,950,010	$780,040	$—	$179,232	$ 61,729	$3,971,011
Cumulative effect of accounting change [4]	—	(41,108)	(3,533)	—	(696)	958	(44,379)
Net income (loss)	—	87,581	11,656	—	346,538	8,609	454,384
Above-market component of swap agreements with Anadarko [1]	—	51,618	—	—	—	—	51,618
Amortization of beneficial conversion feature of Class C units	—	(3,247)	3,247	—	—	—	—
Distributions to noncontrolling interest owner	—	—	—	—	—	(13,529)	(13,529)
Distributions to unitholders	—	(575,323)	—	—	(318,326)	—	(893,649)
Contributions of equity-based compensation from Anadarko	—	5,613	—	—	114	—	5,727
Other	—	396	—	—	—	—	396
Balance at December 31, 2018	$—	$2,475,540	$791,410	$—	$206,862	$ 57,767	$3,531,579

(1) See Note 6.
(2) See Note 3.
(3) See Note 5.
(4) See Note 1.

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	2018	2017	2016
Cash flows from operating activities			
Net income (loss)	$454,384	$578,218	$602,294
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	337,536	290,874	272,933
Impairments	228,338	178,374	15,535
Non-cash equity-based compensation expense	6,153	4,922	4,735
Deferred income taxes	2,466	2,458	2,555
Accretion and amortization of long-term obligations, net	5,142	4,254	(3,789)
Equity income, net – affiliates	(153,024)	(85,194)	(78,717)
Distributions from equity investment earnings – affiliates	144,299	87,380	82,185
(Gain) loss on divestiture and other, net (1)	(1,312)	(132,388)	14,641
(Gain) loss on interest-rate swaps	7,972	—	—
Lower of cost or market inventory adjustments	752	145	168
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable, net	(56,667)	(16,127)	(48,947)
Increase (decrease) in accounts and imbalance payables and accrued liabilities, net	30,722	(6,930)	58,359
Change in other items, net	13,873	(4,491)	(4,367)
Net cash provided by operating activities	1,020,634	901,495	917,585
Cash flows from investing activities			
Capital expenditures	(1,193,896)	(675,025)	(479,993)
Contributions in aid of construction costs from affiliates	—	1,387	6,135
Acquisitions from affiliates	(254)	(3,910)	(716,465)
Acquisitions from third parties	(161,858)	(155,298)	—
Investments in equity affiliates	(133,335)	(384)	(27)
Distributions from equity investments in excess of cumulative earnings – affiliates	25,607	23,085	21,238
Proceeds from the sale of assets to affiliates	—	—	623
Proceeds from the sale of assets to third parties	3,938	23,564	45,490
Proceeds from property insurance claims	—	22,977	17,465
Net cash used in investing activities	(1,459,798)	(763,604)	(1,105,534)
Cash flows from financing activities			
Borrowings, net of debt issuance costs	2,349,564	369,989	1,297,218
Repayments of debt	(1,040,000)	—	(900,000)
Settlement of the Deferred purchase price obligation – Anadarko (2)	—	(37,346)	—
Increase (decrease) in outstanding checks	(3,206)	5,593	2,079
Proceeds from the issuance of common units, net of offering expenses	—	(183)	25,000
Proceeds from the issuance of Series A Preferred units, net of offering expenses	—	—	686,937
Distributions to unitholders (3)	(893,649)	(801,300)	(671,938)
Distributions to noncontrolling interest owner	(13,529)	(13,569)	(13,784)
Net contributions from (distributions to) Anadarko	—	1,263	(23,491)
Above-market component of swap agreements with Anadarko (3)	51,618	58,551	45,820
Net cash provided by (used in) financing activities	450,798	(417,002)	447,841
Net increase (decrease) in cash and cash equivalents	11,634	(279,111)	259,892
Cash and cash equivalents at beginning of period	78,814	357,925	98,033
Cash and cash equivalents at end of period	$90,448	$78,814	$357,925

Supplemental disclosures			
Accretion expense and revisions to the Deferred purchase price obligation – Anadarko [2]	$—	$(4,094)	$(147,234)
Net distributions to (contributions from) Anadarko of other assets [4]	—	(3,189)	581
Interest paid, net of capitalized interest	148,440	137,326	106,485
Taxes paid (reimbursements received)	2,408	1,194	838
Accrued capital expenditures	196,095	204,309	79,253
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 year ended December 31, 2017. See Note 1.
(2) See Note 3.
(3) See Note 6.
(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 6.

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 5). 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"), Front Range Pipeline LLC ("FRP"), Whitethorn Pipeline Company LLC ("Whitethorn LLC") and Cactus II Pipeline LLC ("Cactus II"). See Note 3. 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 "West Texas complex" refers to the Delaware Basin Midstream, LLC ("DBM") complex and DBJV and Haley systems, all of which were combined into a single complex effective January 1, 2018.
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 and condensate on behalf of itself and as agent for its customers under certain of its contracts. The Partnership provides these midstream services for Anadarko, as well as for third-party customers. As of December 31, 2018, the Partnership's assets and investments consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Gathering systems [1]	12	2	3	2
Treating facilities	14	3	—	3
Natural gas processing plants/trains	21	3	—	2
NGLs pipelines	2	—	—	3
Natural gas pipelines	5	—	—	—
Oil pipelines	—	1	—	2

[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. Mentone Train I, a processing train that is part of the West Texas complex, commenced operation in the fourth quarter of 2018. Mentone Train II, a second processing train that is part of the West Texas complex, is expected to commence operation in the first quarter of 2019.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Merger transactions. On November 7, 2018, WGP, the Partnership, Anadarko and certain of their affiliates entered into a Contribution Agreement and Agreement and Plan of Merger (as may be amended from time to time, the “Merger Agreement”), pursuant to which, among other things, Clarity Merger Sub, LLC, a wholly owned subsidiary of WGP, will merge with and into the Partnership, with the Partnership continuing as the surviving entity and a subsidiary of WGP (the “Merger”). Upon closing of the Merger which is expected to occur in the first quarter of 2019, the common units of the Partnership will no longer be publicly traded and will cease to trade on the NYSE under the symbol “WES.” The common units of WGP will begin trading on the NYSE under the symbol “WES” and WGP will change its name to Western Midstream Partners, LP.

The Merger Agreement also provides that WGP, the Partnership and Anadarko will, and will cause their respective affiliates to, cause the following transactions, among others, to occur immediately prior to the Merger becoming effective in the order as follows: (1) Anadarko E&P Onshore LLC and WGR Asset Holding Company LLC (“WGRAH”) (the “Contributing Parties”) will contribute to the Partnership all of their interests in each of Anadarko Wattenberg Oil Complex LLC, Anadarko DJ Oil Pipeline LLC, Anadarko DJ Gas Processing LLC, Wamsutter Pipeline LLC, DBM Oil Services, LLC, Anadarko Pecos Midstream LLC, Anadarko Mi Vida LLC and APC Water Holdings 1, LLC (“APCWH”) to WGR Operating, LP, Kerr-McGee Gathering LLC and Delaware Basin Midstream, LLC (each wholly owned by the Partnership) in exchange for aggregate consideration of $1.814 billion in cash from the Partnership, minus the outstanding amount payable pursuant to an intercompany note (“APCWH Note Payable”) to be assumed by the Partnership in connection with the transaction, and 45,760,201 of the Partnership’s common units; (2) APC Midstream Holdings, LLC (“AMH”) will sell to the Partnership its interests in Saddlehorn Pipeline Company, LLC and Panola Pipeline Company, LLC in exchange for aggregate consideration of $193.9 million in cash; (3) the Partnership will contribute cash in an amount equal to the outstanding balance of the APCWH Note Payable immediately prior to the effective time to APCWH, and APCWH will pay such cash to Anadarko in satisfaction of the APCWH Note Payable; (4) Class C units will convert into the Partnership’s common units on a one-for-one basis; and (5) the Partnership and its general partner will cause the conversion of the incentive distribution rights (“IDRs”) and the 2,583,068 general partner units held by the general partner into a non-economic general partner interest in the Partnership and 105,624,704 of the Partnership’s common units. The 45,760,201 of the common units to be issued to the Contributing Parties, less 6,375,284 common units to be retained by WGRAH, will be converted into the right to receive an aggregate of 55,360,984 WGP common units upon the consummation of the Merger. See Note 13 for additional information.

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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 for entities not wholly owned:

	Percentage Interest	
Equity investments (1)		
Fort Union	14.81	%
White Cliffs	10.00	%
Rendezvous	22.00	%
Mont Belvieu JV	25.00	%
TEP	20.00	%
TEG	20.00	%
FRP	33.33	%
Whitethorn	20.00	%
Cactus II	15.00	%
Proportionate consolidation (2)		
Marcellus Interest systems	33.75	%
Springfield system	50.10	%
Full consolidation		
Chipeta (3)	75.00	%

(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.

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.

Adjustments to previously issued financial statements. The Partnership's consolidated statements of operations for the year ended December 31, 2018, include adjustments to revenue and cost of product expense of the following amounts: (i) $42.6 million increase in Service revenues - fee based, (ii) $13.8 million increase in Product sales and (iii) $56.4 million increase in Cost of product; all of which relate to the nine months ended September 30, 2018. During the third quarter of 2018, management determined that under ASU 2014-09, Revenue from Contracts with Customers (Topic 606) ("Topic 606") adopted on January 1, 2018, the Partnership's marketing affiliate was acting as the Partnership's agent in certain product sales transactions on behalf of the Partnership and in performing marketing services on behalf of the Partnership's customers. The adjustments have no impact to Operating income (loss), Net income (loss), the balance sheets, cash flows or any non-GAAP metric the Partnership uses to evaluate its operations (see How We Evaluate Our Operations under Part II, Item 7 of this Form 10-K) and are not considered material to the Partnership's results of operations for the year ended December 31, 2018. The Partnership will revise its previously reported unaudited financial statements for the 2018 interim periods to reflect the adjustments in future filings.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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, 2018 (see Note 10). 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 assets from Anadarko, the Partnership is 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.

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 included 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.

Shutdown of gathering systems. In May 2018, after assessing a number of factors, with safety and protection of the environment as the primary focus, the Partnership decided to take the Kitty Draw gathering system in Wyoming (part of the Hilight system) and the Third Creek gathering system in Colorado (part of the DJ Basin complex) permanently out of service. Results for the year ended December 31, 2018, reflect (i) an accrual of $10.9 million in anticipated costs associated with the shutdown of the systems, recorded as a reduction in affiliate Product sales in the consolidated statements of operations and (ii) impairment expense of $134.0 million associated with reducing the net book value of the gathering systems and increasing the asset retirement obligation.

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).

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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.

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 13.

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.

Allowance for uncollectible accounts. 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. The allowance for uncollectible accounts was immaterial at December 31, 2018 and 2017.

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, 2018, imbalance receivables and payables were $8.9 million and $9.5 million, respectively. As of December 31, 2017, imbalance receivables and payables were $1.6 million and $2.9 million, respectively. Net changes in imbalance receivables and payables 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 net realizable value and is reported in Other current assets on the consolidated balance sheets. See Note 11.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 8 for a description of impairments recorded during the years ended December 31, 2018, 2017 and 2016.

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).

In December 2015, there was an initial fire and secondary explosion at the processing facility within the 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. 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.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 during the period. 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. The Partnership has allocated goodwill on its two reporting units: (i) gathering and processing and (ii) transportation. Goodwill is evaluated for impairment annually, as of October 1, or more often as facts and circumstances warrant. An initial qualitative assessment is performed to determine the likelihood of whether or not goodwill is impaired. 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 further testing is not necessary. If a quantitative assessment must be performed and the carrying amount of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value through a charge to impairment expense. The carrying value of goodwill after such an impairment would represent a Level 3 fair value measurement. See Note 9.

Other intangible assets. The Partnership assesses intangible assets, as described in Note 9, 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 12.

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 14.

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.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Revenue and cost of product. Upon adoption of the new revenue recognition standard on January 1, 2018 (discussed in Recently adopted accounting standards), the Partnership changed its accounting policy for revenue recognition as described below.
The Partnership provides gathering, processing, treating, transportation and disposal services pursuant to a variety of contracts. Under these arrangements, the Partnership receives fees and/or retains a percentage of products or a percentage of the proceeds from the sale of the customer’s products. These revenues are included in Service revenues and Product sales in the consolidated statements of operations. Payment is generally received from the customer in the month following the service or delivery of the product. Contracts with customers generally have initial terms ranging from 5 to 10 years.
Service revenues – fee based is recognized for fee-based contracts in the month of service based on the volumes delivered by the customer. Producers’ wells or production facilities are connected to the Partnership’s gathering systems for gathering, processing, treating, transportation and disposal of natural gas, NGLs, condensate, crude oil and produced water, as applicable. Revenues are valued based on the rate in effect for the month of service when the fee is either the same rate per unit over the contract term or when the fee escalates and the escalation factor approximates inflation. Deficiency fees charged to customers that do not meet their minimum delivery requirements are recognized as services are performed based on an estimate of the fees that will be billed upon completion of the performance period. Because of its significant upfront capital investment, the Partnership may charge additional service fees to customers for only a portion of the contract term (i.e., for the first year of a contract or until reaching a volume threshold), and these fees are recognized as revenue over the expected period of customer benefit, which is generally the life of the related properties. The Partnership also recognizes revenue and cost of product expense from marketing services performed on behalf of its customers by Anadarko.
The Partnership also receives Service revenues – fee based from contracts that have minimum volume commitment demand fees and fees that require periodic rate redeterminations based upon the related facility cost of service. These fees include fixed and variable consideration that are recognized on a consistent per-unit rate over the term of the contract. Annual adjustments are made to the cost of service rates charged to customers, and a cumulative catch-up revenue adjustment related to services already provided to the minimum volumes under the contract may be recorded in future periods, with revenues for the remaining term of the contract recognized on a consistent per-unit rate.
Service revenues – product based includes service revenues from percent-of-proceeds gathering and processing contracts that are recognized net of the cost of product for purchases from the Partnership’s customers since it is acting as the agent in the product sale. Keep-whole and percent-of-product agreements result in Service revenues – product based being recognized when the natural gas and/or NGLs are received from the customer as noncash consideration for the services provided. Noncash consideration for these services is valued at the time the services are provided. Revenue from product sales is also recognized, along with the cost of product expense related to the sale, when the product received as noncash consideration is sold to either Anadarko or a third party. When the product is sold to Anadarko, Anadarko is acting as the Partnership’s agent in the product sale, with the Partnership recognizing revenue and related cost of product expense associated with these marketing activities based on the Anadarko sales price to the third party.
The Partnership also purchases natural gas volumes from producers at the wellhead or from a production facility, typically at an index price, and charges the producer fees associated with the downstream gathering and processing services. When the fees relate to services performed after control of the product has transferred to the Partnership, the fees are treated as a reduction of the purchase cost. If the fees relate to services performed before control of the product has transferred to the Partnership, the fees are treated as Service revenues – fee based. Product sales revenue is recognized, along with cost of product expense related to the sale, when the purchased product is sold to either Anadarko or a third party.

The Partnership receives aid in construction reimbursements for certain capital costs necessary to provide services to customers (i.e., connection costs, etc.) under certain service contracts. Aid in construction reimbursements are reflected as a contract liability upon receipt and amortized to Service revenues – fee based over the expected period of customer benefit, which is generally the life of the related properties.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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, of which 2,241,980 units remained available for future issuance as of December 31, 2018. Upon vesting of each phantom unit, 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. Equity-based compensation expense attributable to grants made 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 2012 Omnibus Incentive Compensation Plan, as amended and restated (the "Anadarko Incentive Plan") 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 Plan 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.

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 income 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, 2018 or 2017.
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 on and 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.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Net income (loss) per common unit. The Partnership applies the two-class method in determining net income (loss) per common unit applicable to MLPs having multiple classes of securities including common units, Class C units, general partner units and 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 common 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 5.

Recently adopted accounting standards. Accounting Standards Update ("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, with no impact to the consolidated financial statements.

Revenue from contracts with customers (Topic 606). The Partnership adopted Topic 606 on 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 was recognized in the opening balance of equity and partners' capital was a decrease of $44.4 million. The comparative historical financial information has not been adjusted and continues to be reported under Revenue Recognition (Topic 605) ("Topic 605").

Effective January 1, 2018, the Partnership changed its accounting policy for revenue recognition as detailed below:

- Fee-based gathering / processing. Under Topic 605, fee revenues were 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, deficiency fees were charged and recognized only when the customer did not meet the specified delivery minimums for the completed performance period. Under Topic 606, (i) revenues continue to be recognized based on the rate in effect when the fee is either the same rate per unit over the contract term or when the fee escalates and the escalation factor approximates inflation, (ii) deficiency fees are estimated and recognized during the performance period as the services are performed for the customer's delivered volumes, and (iii) timing differences between Service revenues – fee based recognized and amounts billed to customers are recognized as contract assets or contract liabilities, as appropriate, which results in a change in the timing of revenue and changes to net income as a result of the revenue contract's consideration provisions. In addition, under Topic 606, revenue associated with upfront or limited-term fees is recognized over the expected period of customer benefit, which is generally the life of the related properties. These revenues also include revenues earned for marketing services performed on behalf of the Partnership's customers, and the expense associated with these marketing activities is recognized in cost of product expense, resulting in no impact to Operating income (loss).

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

- Cost of service rate adjustments. Under Topic 605, revenue was recognized based on the amounts billed to customers each period as Service revenues – fee based. Under Topic 606, fixed minimum volume commitment demand fees and variable fees that are also billed on these minimum volumes are recognized as Service revenues – fee based on a consistent per-unit rate over the term of the contract. Annual adjustments are made to the cost of service rates charged to customers, and, as a result, a cumulative catch-up revenue adjustment related to the services already provided under the contract may be recorded in future periods, with revenues for the remaining term of the contract recognized on a consistent per-unit rate. Fees received on volumes in excess of the minimum volumes are recognized as Service revenues – fee based as service is provided to the customer based on the billing rate in effect for the performance period. This revenue recognition timing does not affect billings to customers, and differences between amounts billed and revenue recognized are recorded as contract assets or liabilities, as appropriate.

- Aid in construction. Under Topic 605, aid in construction reimbursements were reflected as a reduction to property, plant and equipment upon receipt (and a reduction to capital expenditures). Under Topic 606, reimbursement of capital costs received from customers is reflected as a contract liability (deferred revenue) upon receipt. The contract liability is amortized to Service revenues – fee based over the expected period of customer benefit, which is generally the life of the related properties.

- Percent-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 provides services, and the Partnership recognized revenue when the product was sold to Anadarko or 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 is presented net within Service revenues – product based because the Partnership is acting as the producer's agent in the product sale.

- Noncash consideration - keep-whole and percent-of-product agreements. Under Topic 605, the Partnership recognized revenues only upon the sale of the related products. Under Topic 606, (i) Service revenues – product based is recognized for the products received as noncash consideration in exchange for the services provided, with the keep-whole noncash consideration value based on the net value of the NGLs over the replacement residue gas cost, and (ii) product sales revenue is recognized, along with cost of product expense related to the sale, when the product is sold to Anadarko or a third party. When the product is sold to Anadarko, Anadarko is acting as the Partnership's agent in the product sale and the Partnership recognizes revenue, along with cost of product expense related to the sale, based on the Anadarko sales price to the third party, resulting in no impact to Operating income (loss).

- Wellhead purchase / sale incorporated into gathering / processing. Under Topic 605, the natural gas purchase cost was recognized as cost of product expense and any specified gathering or processing fees charged to the producer were recognized as revenues. Under Topic 606, the fees charged to the producer under this contract type are recognized as adjustments to the amount recognized in cost of product expense instead of revenues when such fees relate to services performed after control of the product transfers to the Partnership.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

The following tables summarize the impact of adopting Topic 606 on the impacted line items within the consolidated statement of operations and the consolidated balance sheet. The differences between revenue as reported following Topic 606 and revenue as it would have been reported under Topic 605 are due to the changes described above.

thousands	Year Ended December 31, 2018 As Reported	Without Adoption of Topic 606	Effect of Change Increase / (Decrease)
Revenues			
Service revenues – fee based	$ 1,609,245	$ 1,499,424	$ 109,821
Service revenues – product based	85,553	—	85,553
Product sales	293,992	1,306,479	(1,012,487)
Expenses			
Cost of product	431,921	1,270,811	(838,890)
Operation and maintenance	414,784	414,591	193
Depreciation and amortization	337,536	334,551	2,985
Impairments	228,338	228,293	45
Income tax expense (benefit)	2,946	2,816	130
Net income attributable to noncontrolling interest	8,609	8,541	68
Net income (loss) attributable to Western Gas Partners, LP	445,775	427,419	18,356

thousands	December 31, 2018 As Reported	Without Adoption of Topic 606	Effect of Change Increase / (Decrease)
Assets			
Other current assets	$ 25,914	$ 20,515	$ 5,399
Net property, plant and equipment	6,612,073	6,493,274	118,799
Other assets	22,503	22,311	192
Liabilities			
Accrued liabilities	127,921	122,014	5,907
Deferred income taxes	9,697	9,760	(63)
Other liabilities	140,067	2,741	137,326
Equity and partners’ capital			
Total equity and partners’ capital	3,531,579	3,550,359	(18,780)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Accounting standards adopted in 2019. 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. This standard is effective for periods beginning after December 15, 2018, and in the first quarter of 2019, the Partnership fully adopted this standard using the modified retrospective method applied to all leases that existed on January 1, 2019. The Partnership made certain elections allowing the Partnership not to reassess contracts that commenced prior to adoption, to continue applying its current accounting policy for existing or expired land easements and not to recognize ROU assets or lease liabilities for short-term leases. Upon adoption, the Partnership recognized approximately $10.0 million of ROU assets and corresponding lease liabilities on the consolidated balance sheet. The adoption of this ASU did not have a material impact on the consolidated statement of operations or the consolidated statement of cash flows. The Partnership has implemented the necessary changes to its business processes, systems and controls to support accounting and disclosure requirements under this ASU.

2. REVENUE FROM CONTRACTS WITH CUSTOMERS

The following table summarizes the Partnership’s revenue from contracts with customers:

thousands	Year Ended December 31, 2018
Revenue from customers	
Service revenues – fee based	$ 1,609,245
Service revenues – product based	85,553
Product sales	301,867
Total revenue from customers	1,996,665
Revenue from other than customers	
Net gains (losses) on commodity price swap agreements	(7,875)
Other	1,486
Total revenues and other	$ 1,990,276

Contract balances. Receivables from customers, which are included in Accounts receivable, net on the consolidated balance sheets were $210.0 million and $244.4 million as of December 31, 2018 and 2017, respectively.
Contract assets primarily relate to accrued deficiency fees the Partnership expects to charge customers once the related performance periods are completed. The following table summarizes the current period activity related to contract assets from contracts with customers:

thousands	
Balance at December 31, 2017	$—
Cumulative effect of adopting Topic 606	5,129
Amounts transferred to Accounts receivable, net from contract assets recognized in the adoption effect	(4,952)
Additional estimated revenues recognized	5,414
Balance at December 31, 2018	$5,591
Contract assets at December 31, 2018	
Other current assets	$5,399

Other assets	192
Total contract assets from contracts with customers	$5,591

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2. REVENUE FROM CONTRACTS WITH CUSTOMERS (CONTINUED)

Contract liabilities primarily relate to (i) fees that are charged to customers for only a portion of the contract term and must be recognized as revenues over the expected period of customer benefit, (ii) fixed and variable fees under cost of service contracts that are received from customers for which revenue recognition is deferred and (iii) aid in construction payments received from customers that must be recognized over the expected period of customer benefit. The following table summarizes the current period activity related to contract liabilities from contracts with customers:

thousands	
Balance at December 31, 2017	$—
Cumulative effect of adopting Topic 606	120,717
Cash received or receivable, excluding revenues recognized during the period	53,064
Assets received from customer	12,933
Revenues recognized during the period that were included in the adoption effect [1]	(11,137)
Cumulative catch up adjustment for change in estimated consideration due to cost of service rate updates	(21,848)
Balance at December 31, 2018	$ 153,729
Contract liabilities at December 31, 2018	
Accrued liabilities	$ 16,403
Other liabilities	137,326
Total contract liabilities from contracts with customers	$ 153,729

(1) Includes $(7.5) million from a performance obligation satisfied in a previous period related to the arbitration against SWEPI LP (see Note 14).

Transaction price allocated to remaining performance obligations. Revenues expected to be recognized from certain performance obligations that are unsatisfied (or partially unsatisfied) as of December 31, 2018, are reflected in the following table. The Partnership applies the optional exemptions in Topic 606 and does not disclose consideration for remaining performance obligations with an original expected duration of one year or less or for variable consideration related to unsatisfied (or partially unsatisfied) performance obligations. Therefore, the following table represents only a portion of expected future revenues from existing contracts as most future revenues from customers are dependent on future variable customer volumes and, in some cases, variable commodity prices for those volumes.

thousands	
2019	$ 470,247
2020	554,099
2021	533,861
2022	530,528
2023	488,603
Thereafter	1,802,153
Total	$ 4,379,491

3. ACQUISITIONS AND DIVESTITURES

Red Bluff Express acquisition. In January 2019, the Partnership acquired a 30% interest in Red Bluff Express Pipeline, LLC ("Red Bluff Express"), which owns a natural gas pipeline operated by a third party (the "Red Bluff Express pipeline") connecting Reeves County and Loving County, Texas to the WAHA hub in Pecos County, Texas. The Partnership acquired its 30% interest from a third party via an initial net investment of $92.5 million, which represented its share of costs incurred up to the date of acquisition. The initial investment was funded with cash on hand and the interest in Red Bluff Express will be accounted for under the equity method.

Whitethorn LLC acquisition. In June 2018, the Partnership acquired a 20% interest in Whitethorn LLC, which owns a crude oil and condensate pipeline that originates in Midland, Texas and terminates in Sealy, Texas (the "Midland-to-Sealy pipeline") and related storage facilities (collectively referred to as "Whitethorn"). A third party operates Whitethorn and oversees the related commercial activities. In connection with its investment in Whitethorn, the Partnership will share proportionally in the commercial activities. The Partnership acquired its 20% interest via a $150.6 million net investment, which was funded with cash on hand and is accounted for under the equity method. See Note 10.

Cactus II acquisition. In June 2018, the Partnership acquired a 15% interest in Cactus II, which will own a crude oil pipeline operated by a third party (the "Cactus II pipeline") connecting West Texas to the Corpus Christi area. The Cactus II pipeline is under construction and is expected to become operational in late 2019. The Partnership acquired its 15% interest from a third party via an initial net investment of $12.1 million, which represented its share of costs incurred up to the date of acquisition. The initial investment was funded with cash on hand and the interest in Cactus II is accounted for under the equity method. See Note 10.

Property exchange. In March 2017, the Partnership acquired an additional 50% interest in the Delaware Basin JV Gathering LLC ("DBJV") system (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 was reflected as a nonmonetary transaction whereby the acquired Additional DBJV System Interest was 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.

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. 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.

3. ACQUISITIONS AND DIVESTITURES (CONTINUED)

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.

Springfield acquisition. In March 2016, 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 originally entered into in February 2014, (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 5 for further information regarding the Series A Preferred units.

Newcastle system divestiture. In December 2018, the Newcastle system, located in Northeast Wyoming, was sold to a third party for $3.2 million, resulting in a net gain on sale of $0.6 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations. The Partnership previously held a 50% interest in, and operated, the Newcastle system.

Helper and Clawson systems 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.

Hugoton system 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. The Partnership allocated $1.6 million in goodwill to this divestiture.

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4. 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
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	0.920	216,586	February 2018
2018			
March 31	$ 0.935	$ 221,133	May 2018
June 30	0.950	225,691	August 2018
September 30	0.965	230,239	November 2018
December 31 (1)	0.980	234,787	February 2019

(1) The Board of Directors declared a cash distribution to the Partnership's unitholders for the fourth quarter of 2018 of $0.980 per unit, or $234.8 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, 2019, to unitholders of record at the close of business on February 1, 2019.

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.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

4. PARTNERSHIP DISTRIBUTIONS (CONTINUED)

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 earlier of (i) the consummation of the Merger or (ii) March 1, 2020, unless the Partnership elects to convert such units earlier or Anadarko extends the conversion date, and the Class C units are disregarded with respect to distributions of the Partnership's available cash until such event. 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 5 for further discussion of the Class C units.

Series A Preferred unit distributions. As further described in Note 5, 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. 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. 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.

General partner interest and incentive distribution rights. As of December 31, 2018, 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.

5. EQUITY AND PARTNERS' CAPITAL

Equity offerings. 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 (the "$500.0 million COP"). Upon the consummation of the Merger (see Note 1), the Partnership will terminate the registration statement relating to the $500.0 million COP and, therefore, common units will no longer be available for issuance thereunder.

Class C units. In November 2014, the Partnership issued 10,913,853 Class C units to 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, and in February 2017, Anadarko elected to extend the conversion date of the Class C units to March 1, 2020. All outstanding Class C units will convert into the Partnership's common units on a one-for-one basis immediately prior to the closing of the Merger, if consummated. If the Merger is not consummated, the conversion will occur on March 1, 2020, unless the Partnership elects to convert such units earlier or Anadarko extends the conversion date (see Note 1).

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 included in the calculation of earnings per unit.

Series A Preferred units. In 2016, the Partnership issued 21,922,831 Series A Preferred units to private investors, generating proceeds of $686.9 million (net of fees and expenses, but including a 2.0% transaction fee paid to the private investors). 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.

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.

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5. 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 Partnership's units issued during the years ended December 31, 2018 and 2017:

	Common Units	Class C Units	Series A Preferred Units	General Partner Units	Total
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
PIK Class C units	—	1,128,782	—	—	1,128,782
Long-Term Incentive Plan award vestings	7,180	—	—	—	7,180
Balance at December 31, 2018	152,609,285	14,372,665	—	2,583,068	169,565,018

Holdings of Partnership equity. As of December 31, 2018, WGP held 50,132,046 common units, representing a 29.6% 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, 2018, (i) other subsidiaries of Anadarko collectively held 2,011,380 common units and 14,372,665 Class C units, representing an aggregate 9.7% limited partner interest in the Partnership and (ii) the public held 100,465,859 common units, representing the remaining 59.2% limited partner interest in the Partnership.

Net income (loss) per common unit. 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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5. 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 4). The common and Class C unitholders' allocation is equal to their cash distributions plus their respective allocations 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 common unit:

	Year Ended December 31,		
thousands except per-unit amounts	2018	2017	2016
Net income (loss) attributable to Western Gas Partners, LP	$445,775	$567,483	$591,331
Pre-acquisition net (income) loss allocated to Anadarko	—	—	(11,326)
Series A Preferred units interest in net (income) loss [1]	—	(42,373)	(76,893)
General partner interest in net (income) loss	(346,538)	(303,835)	(236,561)
Common and Class C limited partners' interest in net income (loss)	$99,237	$221,275	$266,551
Net income (loss) allocable to common units [1]	$84,334	$192,066	$226,611
Net income (loss) allocable to Class C units [1]	14,903	29,209	39,940
Common and Class C limited partners' interest in net income (loss)	$99,237	$221,275	$266,551
Net income (loss) per unit			
Common units – basic and diluted [2]	$0.55	$1.30	$1.74
Weighted-average units outstanding			
Common units – basic and diluted	152,606	147,194	130,253
Excluded due to anti-dilutive effect:			
Class C units [2]	13,795	12,776	11,945
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 would be anti-dilutive for all periods presented and the conversion of Series A Preferred units would be anti-dilutive for the years ended December 31, 2017 and 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.

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6. 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 natural gas, condensate and NGLs to Anadarko. Anadarko sells such natural gas, condensate and NGLs as an agent on behalf of either the Partnership or the Partnership's customers. When such sales are on the Partnership's customers' behalf, the Partnership recognizes associated service revenues and cost of product expense. When such sales are on the Partnership's behalf, the Partnership recognizes product sales revenues based on the Anadarko sales price to the third party and cost of product expense associated with these sales activities.
In addition, the Partnership purchases natural gas, condensate and NGLs 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.

Merger transactions. As discussed in more detail in Note 1, the Partnership has entered into the Merger Agreement with WGP, Anadarko and certain of their affiliates.

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 $279.6 million and $325.2 million at December 31, 2018 and 2017, 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 had commodity price swap agreements with Anadarko to mitigate exposure to the commodity price risk inherent in its percent-of-proceeds, percent-of-product and keep-whole contracts. Notional volumes for each of the commodity price swap agreements were not specifically defined. Instead, the commodity price swap agreements applied to the actual volume of natural gas, condensate and NGLs purchased and sold. The commodity price swap agreements did not satisfy the definition of a derivative financial instrument and, therefore, were not required to be measured at fair value. The Partnership's net gains (losses) on commodity price swap agreements were $(7.9) million, $0.6 million and $28.5 million for the years ended December 31, 2018, 2017 and 2016, respectively, and are reported in the consolidated statements of operations as affiliate Product sales in 2018 and as affiliate Product sales and Cost of product in 2017 and 2016 (see Note 1). These commodity price swap agreements expired without renewal on December 31, 2018.

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6. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Swap agreements - DJ Basin complex, Hugoton system and MGR assets. 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 sold and purchased during 2016, 2017 and 2018 for the DJ Basin complex, MGR assets and Hugoton system are recognized in the consolidated statements of operations at the applicable market price in the tables below. The Partnership also records a capital contribution from Anadarko in its consolidated statements of equity and partners' capital for an amount equal to (i) the amount by which the swap price for product sales exceeds the applicable market price in the tables below, minus (ii) the amount by which the swap price for product purchases exceeds the applicable market price in the tables below. For the years ended December 31, 2018, 2017 and 2016, the capital contributions from Anadarko were $51.6 million, $58.6 million and $45.8 million, respectively. The tables below summarize the swap prices compared to the forward market prices:

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

	Hugoton System (2)	
per barrel except natural gas	2016 Swap Prices	2016 Market Prices (1)
Condensate	$78.61	$ 18.81
Natural gas (per MMBtu)	5.50	2.12

	MGR Assets		
per barrel except natural gas	2016 - 2018 Swap Prices	2017 Market Prices (1)	2018 Market Prices (1)
Ethane	$23.11	$ 4.08	$ 2.52
Propane	52.90	19.24	25.83
Isobutane	73.89	25.79	30.03
Normal butane	64.93	25.16	29.82
Natural gasoline	81.68	45.01	47.25
Condensate	81.68	53.55	56.76

Natural gas (per MMBtu)	4.87	3.05	2.21

(1) Represents the New York Mercantile Exchange forward strip price as of December 8, 2015, December 1, 2016, and December 20, 2017, for the 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 3.

6. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Gathering and processing agreements. The Partnership has significant gathering and processing arrangements with affiliates of Anadarko on a majority of its systems. The combination of the DBM complex and DBJV and Haley systems, effective January 1, 2018, into a single complex now referred to as the “West Texas complex” resulted in natural gas throughput previously reported as “Gathering, treating and transportation” now being reported as “Processing.” The Partnership’s natural gas gathering, treating and transportation throughput (excluding equity investment throughput) attributable to production owned or controlled by Anadarko was 7%, 34% and 37% for the years ended December 31, 2018, 2017 and 2016, respectively. The Partnership’s natural gas processing throughput (excluding equity investment throughput) attributable to production owned or controlled by Anadarko was 41% for each of the years ended December 31, 2018 and 2017, and 54% for the year ended December 31, 2016. The Partnership’s crude oil, NGLs and produced water gathering, treating, transportation and disposal throughput (excluding equity investment throughput) attributable to production owned or controlled by Anadarko was 73%, 56% and 65% for the years ended December 31, 2018, 2017 and 2016, respectively.

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 that acts as an agent in the sale to a third party. 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 (see Note 3).

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	2018	2017	2016
General and administrative expenses	$35,077	$31,733	$29,360
Public company expenses	15,409	9,379	8,410
Total reimbursement	$50,486	$41,112	$37,770

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 expired in May 2018, but was extended for a twelve-month period and will continue to 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.

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6. TRANSACTIONS WITH AFFILIATES (CONTINUED)

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. This management services fee was allocated to the Partnership based on its proportionate share of Anadarko's revenues and expenses 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 benefit 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 agreement 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.

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, 2018, 2017 and 2016. As of December 31, 2018, there was $0.1 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, 2018, 2017 and 2016:

	2018		2017		2016	
	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	$ 55.73	7,180	$ 49.30	7,304	$ 68.78	5,477
Vested	55.73	(7,180)	49.30	(7,304)	68.78	(5,477)
Granted	49.88	8,020	55.73	7,180	49.30	7,304
Phantom units outstanding at end of year	49.88	8,020	55.73	7,180	49.30	7,304

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6. TRANSACTIONS WITH AFFILIATES (CONTINUED)

WGP LTIP and Anadarko Incentive Plan. General and administrative expenses included $6.6 million, $4.6 million and $5.2 million for the years ended December 31, 2018, 2017 and 2016, 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 Anadarko Incentive Plan. Of these amounts, $5.7 million, $4.6 million and $4.2 million are reflected as contributions to partners' capital in the Partnership's consolidated statements of equity and partners' capital for the years ended December 31, 2018, 2017 and 2016, respectively. As of December 31, 2018, the Partnership estimated that $12.5 million of estimated unrecognized compensation expense attributable to the Anadarko Incentive Plan will be allocated to the Partnership over a weighted-average period of 2.0 years.

Affiliate asset contributions and distributions. The following table summarizes Anadarko's contributions and distributions of other assets to the Partnership:

	Year Ended December 31,					
	2018	2017	2016	2018	2017	2016
thousands	Purchases			Sales		
Cash consideration	$(254)	$(3,910)	$(3,965)	$—	$—	$623
Net carrying value	254	5,283	3,366	—	—	(605)
Partners' capital adjustment	$—	$1,373	$(599)	$—	$—	$18

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. For periods prior to January 1, 2018, the cash receipts resulting from such reimbursements were presented as "Contributions in aid of construction costs from affiliates" within the investing section of the consolidated statements of cash flows. As discussed in Recently adopted accounting standards in Note 1, upon adoption of Topic 606, affiliate reimbursements of capital costs are reflected as contract liabilities upon receipt, amortized to Service revenues – fee based over the expected period of customer benefit, and presented within the operating section of the consolidated statements of cash flows.

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6. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Summary of affiliate transactions. The following table summarizes material affiliate transactions:

	Year ended December 31,		
thousands	2018	2017	2016
Revenues and other [1]	$ 1,067,860	$ 1,365,318	$ 1,228,232
Equity income, net – affiliates [1]	153,024	85,194	78,717
Cost of product [1]	193,663	86,010	80,455
Operation and maintenance [2]	98,769	72,489	72,330
General and administrative [3]	45,359	39,130	38,066
Operating expenses	337,791	197,629	190,851
Interest income [4]	16,900	16,900	16,900
Interest expense [5]	—	71	(7,747)
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]	514,906	452,777	382,711
Above-market component of swap agreements with Anadarko	51,618	58,551	45,820

(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.

(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 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 Plan within this Note 6) and amounts charged by Anadarko under the omnibus agreement.

(4) Represents interest income recognized on the note receivable from Anadarko.

(5) Includes amounts related to the Deferred purchase price obligation - Anadarko (see Note 3 and Note 13).

(6)

Represents the cash payment to Anadarko for the settlement of the Deferred purchase price obligation - Anadarko (see Note 3).

(7) Represents proceeds from the issuance of 835,841 common units to WGP as partial funding for the acquisition of Springfield (see Note 3).

(8) Represents distributions paid under the partnership agreement (see Note 4 and Note 5).

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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7. INCOME TAXES

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

	Year Ended December 31,		
thousands	2018	2017	2016
Current income tax expense (benefit)			
Federal income tax expense (benefit)	$—	$—	$4,477
State income tax expense (benefit)	480	2,408	1,340
Total current income tax expense (benefit)	480	2,408	5,817
Deferred income tax expense (benefit)			
Federal income tax expense (benefit)	—	—	1,622
State income tax expense (benefit)	2,466	2,458	933
Total deferred income tax expense (benefit)	2,466	2,458	2,555
Total income tax expense (benefit)	$2,946	$4,866	$8,372

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	2018	2017	2016
Income (loss) before income taxes	$457,330	$583,084	$610,666
Statutory tax rate	— %	— %	— %
Tax computed at statutory rate	$—	$—	$—
Adjustments resulting from:			
Federal taxes on income attributable to Partnership assets pre-acquisition	—	—	6,162
State taxes on income attributable to Partnership assets pre-acquisition (net of federal benefit)	—	—	117
Texas margin tax expense (benefit)	2,946	4,866	2,093
Income tax expense (benefit)	$2,946	$4,866	$8,372
Effective tax rate	1 %	1 %	1 %

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

	December 31,	
thousands	2018	2017
Depreciable property	$(10,057)	$(7,676)
Credit carryforwards	497	448
Other intangible assets	(299)	(189)
Other	162	8
Net long-term deferred income tax liabilities	$(9,697)	$(7,409)

Credit carryforwards, which are available for use on future income tax returns, consist of $0.5 million of state income tax credits that expire in 2026.

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8. PROPERTY, PLANT AND EQUIPMENT

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

		December 31,	
thousands	Estimated Useful Life	2018	2017
Land	n/a	$4,653	$4,450
Gathering systems and processing complexes	15 to 40 years	8,550,373	7,113,114
Pipelines and equipment	6 to 45 years	172,497	137,644
Assets under construction	n/a	490,705	579,501
Other	3 to 40 years	32,000	29,826
Total property, plant and equipment		9,250,228	7,864,535
Less accumulated depreciation		2,638,155	2,133,644
Net property, plant and equipment		$6,612,073	$5,730,891

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 the year ended December 31, 2018, the Partnership recognized impairments of $228.3 million, including impairments of $125.9 million at the Third Creek gathering system and $8.1 million at the Kitty Draw gathering system. These assets were impaired to their estimated salvage values of $1.8 million and zero, respectively, using the market approach and Level 3 fair value inputs, due to the shutdown of the systems. See Note 1 for further information. Also during 2018, the Partnership recognized impairments of $38.7 million and $34.6 million at the Hilight and MIGC systems, respectively. These assets were impaired to their estimated fair values of $4.9 million and $15.2 million, respectively, using the income approach and Level 3 fair value inputs, due to a reduction in estimated future cash flows. The remaining $21.0 million of impairments was primarily related to (i) a $10.9 million impairment at the GNB NGL pipeline, which was impaired to its estimated fair value of $10.0 million using the income approach and Level 3 fair value inputs, and (ii) a $5.6 million impairment related to an idle facility at the Chipeta complex, which was impaired to its estimated salvage value of $1.5 million using the market approach and Level 3 fair value inputs.

During the year ended December 31, 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, (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 the year ended December 31, 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.

9. 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). The Partnership's annual qualitative goodwill impairment assessment as of October 1, 2018, indicated no impairment. Qualitative factors were also assessed in the fourth quarter of 2018 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 38 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	2018	2017
Gross carrying amount	$868,035	$868,035
Accumulated amortization	(121,231)	(92,766)
Other intangible assets	$746,804	$775,269

Amortization expense for intangible assets was $28.5 million for the year ended December 31, 2018, and $28.4 million for each of the years ended December 31, 2017 and 2016. Intangible asset amortization recorded in each of the next five years is estimated to be $28.9 million for the years ended December 31, 2019 to December 31, 2022, and $28.6 million for the year ended December 31, 2023.

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10. EQUITY INVESTMENTS

The following tables present the activity in the Partnership's equity investments for the years ended December 31, 2018 and 2017:

thousands	Balance at December 31, 2016	Impairment expense (1)	Equity income, net	Contributions	Distributions	Distributions in excess of cumulative earnings (2)	Balance at December 31, 2017
Fort Union	$ 12,833	$ (3,110)	$ 3,821	$ —	$ (4,217)	$ (2,297)	$ 7,030
White Cliffs	47,319	—	12,547	277	(11,965)	(3,233)	44,945
Rendezvous	46,739	—	1,144	—	(3,085)	(2,270)	42,528
Mont Belvieu JV	112,805	—	29,444	—	(29,482)	(2,468)	110,299
TEG	15,846	—	3,350	—	(3,317)	—	15,879
TEP	189,194	—	17,387	107	(17,639)	(10,074)	178,975
FRP	169,472	—	17,501	—	(17,675)	(2,743)	166,555
Total	$ 594,208	$ (3,110)	$ 85,194	$ 384	$ (87,380)	$ (23,085)	$ 566,211

thousands	Balance at December 31, 2017	Acquisitions	Equity income, net	Contributions (3)	Distributions	Distributions in excess of cumulative earnings (2)	Balance at December 31, 2018
Fort Union	$ 7,030	$ —	$ (1,433)	$ —	$ (194)	$ (3,144)	$ 2,259
White Cliffs	44,945	—	11,841	1,278	(11,259)	(3,785)	43,020
Rendezvous	42,528	—	767	—	(2,709)	(2,745)	37,841
Mont Belvieu JV	110,299	—	29,200	—	(29,239)	(5,311)	104,949
TEG	15,879	—	4,290	3,720	(4,368)	(163)	19,358
TEP	178,975	—	37,963	11,980	(33,552)	(2,168)	193,198
FRP	166,555	—	23,308	14,980	(23,481)	(4,926)	176,436
Whitethorn	—	150,563	47,088	7,069	(39,497)	(3,365)	161,858
Cactus II	—	12,052	—	94,308	—	—	106,360
Total	$ 566,211	$ 162,615	$ 153,024	$ 133,335	$ (144,299)	$ (25,607)	$ 845,279

(1) Recorded in Impairments in the consolidated statements of operations.
(2) 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.
(3) Includes capitalized interest of $1.4 million related to the construction of the Cactus II pipeline.

The investment balance in Fort Union at December 31, 2018, 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 2017 for its investment in Fort Union.
The investment balance in Rendezvous at December 31, 2018, includes $34.3 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 to Equity income, net – affiliates over the remaining estimated useful life of those facilities.

10. EQUITY INVESTMENTS (CONTINUED)

The investment balance in White Cliffs at December 31, 2018, is $6.4 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.

The investment balance in Whitethorn at December 31, 2018, is $39.1 million less than the Partnership's underlying equity in Whitethorn's net assets, primarily due to terms of the acquisition agreement which provided the Partnership a share of pre-acquisition operating cash flow. This difference is being amortized to Equity income, net – affiliates over the remaining estimated useful life of Whitethorn.

An impairment loss was recognized by the operator of Fort Union during the year ended December 31, 2016. The Partnership's 14.81% share of the impairment loss was $3.0 million for the year ended December 31, 2016, 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	2018	2017	2016
Revenues	$1,087,125	$703,424	$687,554
Operating income	733,802	435,735	428,454
Net income	731,364	434,749	427,511

	December 31,	
thousands	2018	2017
Current assets	$220,912	$137,957
Property, plant and equipment, net	3,426,438	2,512,214
Other assets	35,411	36,373
Total assets	$3,682,761	$2,686,544
Current liabilities	80,109	80,490
Non-current liabilities	12,213	7,447
Equity	3,590,439	2,598,607
Total liabilities and equity	$3,682,761	$2,686,544

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11. COMPONENTS OF WORKING CAPITAL

A summary of accounts receivable, net is as follows:

	December 31,	
thousands	2018	2017
Trade receivables, net	$217,056	$160,387
Other receivables, net	45	45
Total accounts receivable, net	$217,101	$160,432

A summary of other current assets is as follows:

	December 31,	
thousands	2018	2017
NGLs inventory	$6,370	$10,788
Imbalance receivables	8,864	1,640
Prepaid insurance	1,972	2,388
Contract assets	5,399	—
Other	3,309	—
Total other current assets	$25,914	$14,816

A summary of accrued liabilities is as follows:

	December 31,	
thousands	2018	2017
Accrued interest expense	$70,959	$40,632
Short-term asset retirement obligations	25,938	2,304
Short-term remediation and reclamation obligations	863	833
Income taxes payable	384	2,495
Contract liabilities	16,403	—
Other	13,374	1,635
Total accrued liabilities	$127,921	$47,899

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12. ASSET RETIREMENT OBLIGATIONS

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

	Year Ended December 31,	
thousands	2018	2017
Carrying amount of asset retirement obligations at beginning of year	$ 145,698	$ 142,407
Liabilities incurred	16,343	16,153
Liabilities settled	(12,432)	(10,468)
Accretion expense	7,217	6,956
Revisions in estimated liabilities	129,088	(9,350)
Carrying amount of asset retirement obligations at end of year	$ 285,914	$ 145,698

The liabilities incurred for the year ended December 31, 2018, represented additions in asset retirement obligations primarily due to capital expansions at the West Texas and DJ Basin complexes. Revisions in estimated liabilities for the year ended December 31, 2018, primarily included (i) $61.1 million related to changes in expected settlement costs and timing, primarily at the DJ Basin and West Texas complexes and the MGR assets, and (ii) $43.4 million related to the shutdown of the Third Creek gathering system during the second quarter of 2018. See Note 1 for further information.

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.

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13. DEBT AND INTEREST EXPENSE

The following table presents the Partnership’s outstanding debt:

	December 31, 2018			December 31, 2017		
thousands	Principal	Carrying Value	Fair Value [1]	Principal	Carrying Value	Fair Value [1]
2.600% Senior Notes due 2018	$—	$—	$—	$350,000	$349,684	$350,631
5.375% Senior Notes due 2021	500,000	496,959	515,990	500,000	495,815	530,647
4.000% Senior Notes due 2022	670,000	669,078	662,109	670,000	668,849	684,043
3.950% Senior Notes due 2025	500,000	492,837	466,135	500,000	491,885	500,885
4.650% Senior Notes due 2026	500,000	495,710	483,994	500,000	495,245	520,144
4.500% Senior Notes due 2028	400,000	394,631	377,475	—	—	—
4.750% Senior Notes due 2028	400,000	395,841	384,370	—	—	—
5.450% Senior Notes due 2044	600,000	593,349	522,386	600,000	593,234	637,827
5.300% Senior Notes due 2048	700,000	686,648	605,327	—	—	—
5.500% Senior Notes due 2048	350,000	342,328	311,536	—	—	—
RCF	220,000	220,000	220,000	370,000	370,000	370,000
Total long-term debt	$4,840,000	$4,787,381	$4,549,322	$3,490,000	$3,464,712	$3,594,177

(1) Fair value is measured using the market approach and Level 2 inputs.

Debt activity. The following table presents the debt activity of the Partnership for the years ended December 31, 2018 and 2017:

thousands	Carrying Value
Balance at December 31, 2016	$ 3,091,461
RCF borrowings	370,000
Other	3,251
Balance at December 31, 2017	$ 3,464,712
RCF borrowings	540,000
Issuance of 4.500% Senior Notes due 2028	400,000
Issuance of 5.300% Senior Notes due 2048	700,000
Issuance of 4.750% Senior Notes due 2028	400,000
Issuance of 5.500% Senior Notes due 2048	350,000
Repayment of 2.600% Senior Notes due 2018	(350,000)
Repayments of RCF borrowings	(690,000)
Other	(27,331)
Balance at December 31, 2018	$ 4,787,381

13. DEBT AND INTEREST EXPENSE (CONTINUED)

Senior Notes. In August 2018, the 4.750% Senior Notes due 2028 and 5.500% Senior Notes due 2048 were offered to the public at prices of 99.818% and 98.912%, respectively, of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rates of the senior notes are 4.885% and 5.652%, respectively. Interest is paid on each such series semi-annually on February 15 and August 15 of each year, beginning February 15, 2019. The net proceeds were used to repay the maturing 2.600% Senior Notes due August 2018, repay amounts outstanding under the senior unsecured revolving credit facility ("RCF") and for general partnership purposes, including to fund capital expenditures.

In March 2018, the 4.500% Senior Notes due 2028 and 5.300% Senior Notes due 2048 were offered to the public at prices of 99.435% and 99.169%, respectively, of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rates of the senior notes are 4.682% and 5.431%, respectively. Interest is paid on each such series semi-annually on March 1 and September 1 of each year, beginning September 1, 2018. The net proceeds were used to repay amounts outstanding under the RCF and for general partnership purposes, including to fund capital expenditures.

At December 31, 2018, the Partnership was in compliance with all covenants under the indentures governing its outstanding notes.

Revolving credit facility. In February 2018, the Partnership entered into the five-year $1.5 billion RCF by amending and restating the $1.2 billion credit facility that was originally entered into in February 2014. The RCF is expandable to a maximum of $2.0 billion, matures in February 2023, with options to extend maturity by up to two additional one year increments, and bears interest at the London Interbank Offered Rate ("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.

As of December 31, 2018, the Partnership had $220.0 million in outstanding borrowings and $4.6 million in outstanding letters of credit, resulting in $1.3 billion available borrowing capacity under the RCF. As of December 31, 2018 and 2017, the interest rate on any outstanding RCF borrowings was 3.74% and 2.87%, respectively. The facility fee rate was 0.20% at December 31, 2018 and 2017. At December 31, 2018, the Partnership was in compliance with all covenants under the RCF.

In December 2018, the Partnership entered into an amendment to the RCF for (i) subject to the consummation of the Merger (see Note 1), an increase to the size of the RCF to $2.0 billion, while leaving the $0.5 billion accordion feature of the RCF unexercised, and (ii) effective on February 15, 2019, the exercise of one of the Partnership's one-year extension options to extend the maturity date of the RCF to February 2024.

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.

364-day Facility. In December 2018, the Partnership entered into a $2.0 billion 364-day senior unsecured credit agreement (the "364-day Facility"), the proceeds of which will be used to fund substantially all of the cash portion of the consideration under the Merger Agreement and the payment of related transaction costs (see Note 1). The 364-day Facility will mature on the day prior to the one-year anniversary of the completion of the Merger, and will bear interest at LIBOR, plus applicable margins ranging from 1.000% to 1.625%, 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 as defined in the 364-day Facility and plus applicable margins currently ranging from zero to 0.625%, based upon the Partnership's senior unsecured debt rating. The Partnership is also required to pay a ticking fee of 0.175% on the commitment amount beginning 90 days after the effective date of the credit agreement through the date of funding under the 364-day Facility.

Funding of the 364-day Facility is conditioned upon the consummation of the Merger and net cash proceeds received from future asset sales and debt or equity offerings by the Partnership must be used to repay amounts outstanding under the facility.

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13. DEBT AND INTEREST EXPENSE (CONTINUED)

Interest-rate swaps. In December 2018, the Partnership entered into interest-rate swap agreements to manage interest rate risk associated with anticipated 2019 debt issuances. Pursuant to these swap agreements, the Partnership exchanged a floating interest rate indexed to the three-month LIBOR for a fixed interest rate. Depending on market conditions, liability management actions or other factors, the Partnership may settle or amend certain or all of the currently outstanding interest-rate swaps. The following interest-rate swaps were outstanding as of December 31, 2018:

Notional Principal Amount	Reference Period	Mandatory Termination Date	Fixed Interest Rate
$250.0 million	December 2019 - 2024	December 2019	2.730%
$250.0 million	December 2019 - 2029	December 2019	2.856%
$250.0 million	December 2019 - 2049	December 2019	2.905%

The Partnership does not apply hedge accounting and, therefore, gains and losses associated with the interest-rate swaps are recognized currently in earnings. For the year ended December 31, 2018, the Partnership recognized a non-cash loss of $8.0 million, which is included in Other income (expense), net in the consolidated statements of operations.
Valuation of the interest-rate swaps is based on similar transactions observable in active markets and industry standard models that primarily rely on market-observable inputs. Inputs used to estimate fair value in industry standard models are categorized as Level 2 inputs, because substantially all assumptions and inputs are observable in active markets throughout the full term of the instruments. Inputs used to estimate the fair value include market price curves, contract terms and prices, and credit risk adjustments. The fair value of the interest-rate swaps as of December 31, 2018, was an $8.0 million liability, which is reported in Accrued liabilities on the consolidated balance sheets.

Credit risk considerations. Over-the-counter traded swaps expose the Partnership to counterparty credit risk. The Partnership monitors the creditworthiness of its counterparties, establishes credit limits according to the Partnership's credit policies and guidelines, and assesses the impact on the fair value of its counterparties' creditworthiness. The Partnership has the ability to require cash collateral or letters of credit to mitigate its credit risk exposure.
The Partnership's interest-rate swaps are subject to individually negotiated credit provisions that may require collateral of cash or letters of credit depending on the derivative's portfolio valuation versus negotiated credit thresholds. These credit thresholds generally require full or partial collateralization of the Partnership's obligations depending on certain credit risk related provisions. Specifically, the Partnership may be required to post collateral with respect to its interest-rate swaps if its credit ratings decline below current levels, the liability associated with the swaps increases substantially or certain credit event of default provisions occur. For example, based on the derivative positions as of December 31, 2018, if the Partnership's credit ratings from both Standard and Poor's and Moody's Investors Service were below the investment grade thresholds of BBB- and Baa3, respectively, the Partnership would be required to post collateral of up to approximately $2.7 million. The aggregate fair value of interest-rate swaps with credit risk related contingent features for which a net liability position existed was $5.7 million at December 31, 2018.

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13. DEBT AND INTEREST EXPENSE (CONTINUED)

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

	Year Ended December 31,		
thousands	2018	2017	2016
Third parties			
Long-term debt	$(199,322)	$(142,525)	$(121,832)
Amortization of debt issuance costs and commitment fees	(8,207)	(6,616)	(6,398)
Capitalized interest	23,521	6,826	5,562
Total interest expense – third parties	(184,008)	(142,315)	(122,668)
Affiliates			
Deferred purchase price obligation – Anadarko[1]	—	(71)	7,747
Total interest expense – affiliates	—	(71)	7,747
Interest expense	$(184,008)	$(142,386)	$(114,921)

(1) See Note 3 for a discussion of the Deferred purchase price obligation - Anadarko.

14. 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, 2018 and 2017, the consolidated balance sheets included $1.7 million and $1.8 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 Other liabilities. 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 its 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 11 and Note 12.

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 sought to collect certain gathering fees under the GGA for the period January 1, 2016 to July 1, 2017. SWEPI disputed DBJV's calculation of the cost of service based rate and filed a counterclaim alleging overpayment of fees under the GGA for the years 2013 through 2015. As part of the adoption of Topic 606 (see Note 1), during the first quarter of 2018, the Partnership recorded a $7.5 million contract liability and reduced total equity and partners' capital related to the counterclaim for the years 2013 through 2015 under the GGA revenue contract. The arbitration hearing concluded on June 27, 2018. On September 14, 2018, the panel issued a binding non-appealable decision awarding no damages to either DBJV or SWEPI. As such, during the third quarter of 2018, the previously recorded contract liability was reversed, resulting in a $7.5 million increase to Service revenues - fee based in the consolidated statements of operations.
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 for which the final disposition could have a material adverse effect on the Partnership's financial condition, results of operations or cash flows.

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14. COMMITMENTS AND CONTINGENCIES (CONTINUED)

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 construction and expansion projects at the West Texas and DJ Basin 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 $53.6 million, $45.1 million and $37.5 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Operating leases. The amounts in the table below represent existing contractual operating lease obligations as of December 31, 2018, that may be assigned or otherwise charged to the Partnership pursuant to the reimbursement provisions of the omnibus agreement:

thousands	Operating Leases
2019	$ 8,711
2020	2,236
2021	460
2022	467
2023	473
Thereafter	1,547
Total	$ 13,894

See Accounting standards adopted in 2019 in Note 1 for a discussion of the expected impact the adoption of ASU 2016-02, Leases (Topic 842) will have on the consolidated financial statements.

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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, 2018 and 2017. 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 3—Acquisitions and Divestitures.

thousands except per-unit amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2018				
Total revenues and other [1]	$456,802	$467,919	$507,762	$557,793
Equity income, net – affiliates	20,424	39,218	43,110	50,272
Cost of product [1]	97,433	100,119	105,966	128,403
Operating income (loss)	188,126	74,736	200,321	166,210
Net income (loss)	152,348	35,519	155,636	110,881
Net income (loss) attributable to Western Gas Partners, LP	149,363	32,708	154,646	109,058
Net income (loss) per common unit – basic and diluted [2]	0.38	(0.32)	0.39	0.10
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
Cost of product	189,359	203,277	239,223	276,834
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 [2]	0.01	0.49	0.38	0.39

(1) See Adjustments to previously issued financial statements in Note 1—Summary of Significant Accounting Policies.
(2) 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, 2018.

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

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

Changes in Internal Control Over Financial Reporting. There were no changes in our internal control over financial reporting during the quarter ended December 31, 2018, that have materially affected, or are reasonably likely to materially affect, the Partnership's internal control over financial reporting.

Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

Management of Western Gas Partners, LP

As 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 nine 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 $16.4 million in gas purchase and sale transactions during 2018. 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 board structure has historically 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. From November 15, 2018 through December 31, 2018, Mr. Fink served as our general partner's Chief Executive Officer while also serving as Chairman of the Board for our general partner's Board of Directors. 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 18, 2019.

Name	Age	Position with Western Gas Holdings, LLC
Benjamin M. Fink	48	President, Chief Executive Officer and Director (through November 15, 2018) Chief Executive Officer and Chairman of the Board (from November 15, 2018 through December 31, 2018) Chairman of the Board (beginning January 1, 2019)
Jaime R. Casas	48	Senior Vice President, Chief Financial Officer and Treasurer
Robin H. Fielder	38	President and Director (both effective November 15, 2018) Chief Executive Officer (effective January 1, 2019)
Gennifer F. Kelly	46	Senior Vice President and Chief Operating Officer (effective May 13, 2018)
Philip H. Peacock	47	Senior Vice President, General Counsel and Corporate Secretary
Robert G. Gwin	55	Chairman of the Board (through November 14, 2018) Director (effective November 15, 2018)
Steven D. Arnold	58	Director
Daniel E. Brown	43	Director
Milton Carroll	68	Director
James R. Crane	65	Director
Mitchell W. Ingram	56	Director (effective November 15, 2018)
David J. Tudor	59	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.

Benjamin M. Fink	Biography/Qualifications
Age: 48 Houston, Texas Director since: February 2017 Not Independent Officer since: 2009	Benjamin M. Fink has served as Chairman of the Board of our and WGP's general partners since November 2018. He served as President of our and WGP's general partners from May 2017 to November 2018 and as Chief Executive Officer from May 2017 to December 2018. In addition, he has served as a director of our and WGP's general partners since February 2017. He previously served as President, Chief Executive Officer, Chief Financial Officer and Treasurer of our and WGP's general partners 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's general partner from its formation in September 2012 to February 2017. Mr. Fink was named Executive Vice President, Finance and Chief Financial Officer of Anadarko in November 2018. Prior to that, Mr. Fink served as Senior Vice President beginning in February 2017 and previously served as Vice President, Finance and Assistant Treasurer since May 2013, having joined Anadarko in 2007. 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.

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	Biography/Qualifications
Jaime R. Casas Age: 48 Houston, Texas Officer since: May 2017	Jaime R. Casas has served as Senior Vice President, Chief Financial Officer and Treasurer of our and WGP's general partners since May 2017. Mr. Casas also has served as 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.
Robin H. Fielder Age: 38 Houston, Texas Director since: November 2018 Not Independent Officer since: November 2018	Biography/Qualifications Robin H. Fielder has served as President and Chief Executive Officer of our and WGP's general partners since January 2019, and as President of our and WGP's general partners from November 2018 to January 2019. Ms. Fielder has also served as Senior Vice President, Midstream of Anadarko since November 2018. Prior to these positions, Ms. Fielder served in positions of increasing responsibility at Anadarko, including Vice President, Investor Relations from September 2016 to November 2018, Midstream Corporate Planning Manager from December 2015 to September 2016, Director, Investor Relations from June 2014 to December 2015 and General Manager, Carthage/North Louisiana from June 2013 to June 2014. Prior to serving in these roles, Ms. Fielder held various exploration and operations engineering positions at Anadarko in both the U.S. onshore and the deepwater Gulf of Mexico.
	Biography/Qualifications
Gennifer F. Kelly Age: 46 Houston, Texas Officer since: May 2018	Gennifer F. Kelly has served as Senior Vice President and Chief Operating Officer of our and WGP's general partners since May 2018. Ms. Kelly has also served as Vice President, Midstream and Marketing for Anadarko since April 2018. From October 2017 to April 2018, she served as Director of Operations Transformation responsible for streamlining safety processes across Anadarko. From March 2016 to October 2017, she served as Director of Strategic Planning, and previously served as General Manager over Anadarko's East Texas and Louisiana operations beginning in December 2014. Ms. Kelly has more than 24 years of experience in the oil and natural gas industry, joining Kerr-McGee Corporation in 1998. She has since held a variety of positions within Anadarko, including Business Advisor for Planning and Reserves Administration in the U.S. Onshore Southern and Appalachia Region, Completions Manager for Permian Basin, East Texas and North Louisiana, and engineering positions in both the U.S. onshore and the Gulf of Mexico.
Philip H. Peacock Age: 47 Houston, Texas	Biography/Qualifications Philip H. Peacock has served as Senior Vice President, General Counsel and Corporate Secretary of our and WGP's general partners 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

Officer since: August 2012	February 2017. In August 2018, Mr. Peacock was named Vice President, Deputy General Counsel, Corporate Secretary and Chief Compliance Officer of Anadarko. Prior to joining the Partnership, Mr. Peacock was a partner practicing corporate and 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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Robert G. Gwin Age: 55 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 served as Chairman of the Board of our general partner from 2009 to November 2018. He also served as Chief Executive Officer of our general partner from 2007 to 2010 and as President from 2007 to 2009. Mr. Gwin also served as Chairman of the Board of WGP GP from September 2012 to November 2018. He was named President of Anadarko in November 2018. Prior to this position, he served as Executive Vice President, Finance and Chief Financial Officer of Anadarko since May 2013; Senior Vice President, Finance and Chief Financial Officer of Anadarko since March 2009; and Senior Vice President of Anadarko since March 2008. He served as a member of the board of directors of LyondellBasell Industries N.V. from 2011 through November 2018, having served as Chairman of the Board from August 2013 through September 2018.
Steven D. Arnold Age: 58 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: 43 Houston, Texas Director since: November 2017 Not Independent	Biography/Qualifications Daniel E. Brown has served as a director of our and WGP's general partners since November 2017. Mr. Brown has served as Executive Vice President, U.S. Onshore Operations, with responsibility for Anadarko's upstream 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: 68 Houston, Texas Director since:	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

2008 Independent	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.

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	Biography/Qualifications
James R. Crane Age: 65 Houston, Texas Director since: April 2008 Independent	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 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 and Cargojet Inc., a Canadian cargo services company. 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.
	Biography/Qualifications
Mitchell W. Ingram Age: 56 Houston, Texas Director since: November 2018 Not Independent	Mitchell W. Ingram has served as a director of our and WGP's general partners since November 2018. Mr. Ingram has served as Executive Vice President, International, Deepwater and Exploration of Anadarko since May 2018. Prior to this position, he served as Executive Vice President, International & Deepwater Operations and Project Management of Anadarko since October 2017. He joined Anadarko as Executive Vice President, Global LNG in November 2015. Prior to joining Anadarko, Mr. Ingram was with BG Group since 2006, where he served as a member of the Executive Committee in the role of Executive Vice President-Technical since March 2015. Previously, he held positions of increasing responsibility with the company's LNG project in Queensland, Australia, where he served as Managing Director of QGC, a BG Group business, since April 2014; as Deputy Managing Director since September 2013; and as Project Director of the Queensland Curtis LNG project since May 2012. From 2006 to May 2012, Mr. Ingram was Asset General Manager of BG Group's Karachaganak interest in Kazakhstan. He joined BG Group after 20 years with Occidental Oil & Gas, where he held several U.K. and international leadership positions in project management, development, and operations.
	Biography/Qualifications
David J. Tudor Age: 59 Houston, Texas Director since: 2008 Independent	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, 2018.

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 2018.
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 four meetings during 2018.

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 2018 were Benjamin M. Fink (the principal executive officer), Jaime R. Casas (the principal financial officer and principal accounting officer), Robin H. Fielder (president of our general partner effective November 15, 2018), Gennifer F. Kelly (the principal operating officer effective May 13, 2018) and Philip H. Peacock (the senior vice president, general counsel and corporate secretary). Compensation paid or awarded by us in 2018 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 the named executive officers are eligible to be paid or awarded with respect to each element of compensation for services rendered to both our general partner and Anadarko, such aggregate amount is then multiplied by a time 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 that we reimburse Anadarko for pursuant to the terms of the omnibus agreement, and such amount 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 percentages of time ("time allocation") that the general partner's named executive officers devoted to the Partnership during the fiscal year ended December 31, 2018, which percentages represent the time devoted to the business of the Partnership relative to the aggregate time devoted to the businesses of the Partnership and Anadarko:

Named Executive Officers of Our General Partner	Time Allocated	Anadarko Corporate Officer
Benjamin M. Fink	80%	Yes
Jaime R. Casas	90%	Yes
Robin H. Fielder (1)	30%	Yes
Gennifer F. Kelly (1)	50%	Yes
Philip H. Peacock	50%	Yes

(1) The percentages presented for Ms. Fielder and Ms. Kelly represent the time allocated since their appointments as officers of our general partner.

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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 4, 2019. The elements of compensation discussed below (and Anadarko's decisions with respect to the levels of such compensation) are not subject to approvals by our Board of Directors or the 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 2018, 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, as amended and restated (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 and change of control benefits, and 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). Our named executive officers are eligible to receive annual cash awards from Anadarko to be paid in 2019 for their performance during the year ended December 31, 2018, under the 2018 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 2018, 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 are 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 expenses 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 elements discussed above, Anadarko also provides other benefits to our 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 Anadarko’s 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, please see the Compensation Discussion and Analysis section of Anadarko’s proxy statement for its annual meeting of 2019 stockholders, which is expected to be filed with the SEC no later than April 4, 2019.

Role of Executive Officers in Executive Compensation

Anadarko’s management determines the compensation for each of our named executive officers. The Board of Directors determines compensation for the independent, non-management directors of our 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 and 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 our 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, 2018, 2017 and 2016, 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 2018, 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	2018	401,923	—	1,783,737	578,038	387,144	102,571	3,253,413
President and	2017	415,385	—	2,062,764	1,101,952	325,122	138,498	4,043,721
Chief Executive Officer	2016	332,135	—	1,634,281	401,340	259,066	108,526	2,735,348
Jaime R. Casas	2018	348,577	—	1,650,799	392,547	271,890	89,029	2,752,842
Senior Vice President, Chief	2017	208,731	—	1,257,309	904,934	135,675	71,607	2,578,256
Financial Officer and Treasurer	2016	—	—	—	—	—	—	—
Robin H. Fielder	2018	23,019	—	384,963	201,309	21,313	5,905	636,509
President	2017	—	—	—	—	—	—	—
(effective November 15, 2018)	2016	—	—	—	—	—	—	—
Gennifer F. Kelly	2018	111,927	—	520,799	100,655	87,303	28,674	849,358
Senior Vice President and Chief Operating	2017	—	—	—	—	—	—	—
Officer (effective May 13, 2018)	2016	—	—	—	—	—	—	—
Philip H. Peacock	2018	168,654	—	224,603	117,430	131,550	43,084	685,321
Senior Vice President, General Counsel	2017	150,082	—	906,771	218,869	88,894	50,098	1,414,714
and Corporate Secretary	2016	129,938	—	100,020	—	62,370	42,427	334,755

(1) The amounts in this column reflect the base salary compensation allocated to us by Anadarko for the years ended December 31, 2018, 2017 and 2016. Ms. Fielder's amount reflects base salary compensation earned and allocated since her appointment as President on November 15, 2018. Ms. Kelly's amount reflects base salary compensation earned and allocated since her appointment as the principal operating officer on May 13, 2018.

(2) The amounts in this column reflect the expected allocation to us of the aggregate grant date fair value of the awards, computed in accordance with FASB ASC Topic 718 (without respect to the risk of forfeitures), for non-option stock awards granted pursuant to the Omnibus Plan. The value ultimately realized upon the actual vesting of the award(s) may or may not be equal to this determined value. For a discussion of valuation assumptions for the awards under the Omnibus Plan, see Note 23—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, 2018 (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 2018, 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 Omnibus Plan. See note (2) above for valuation assumptions. The value ultimately realized upon the exercise of the stock option(s) may or may not be equal to this determined value. For a discussion of valuation assumptions for the awards under the Omnibus Plan, see Note 23—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, 2018 (which is not, and shall not be deemed to be, incorporated by reference herein). For information regarding the option awards granted to the named executives in 2018, see the Grants of Plan-Based Awards table.

(4) The amounts in this column reflect the compensation under Anadarko's AIP expected to be allocated to us for the year ended December 31, 2018, and allocated to us for the years ended December 31, 2017 and 2016. Given the timing of when payments are to be made in 2019, the 2018 amounts represent estimates of the payments which were earned in 2018 and are expected to be paid in early 2019, which may not be indicative of the payout our named executive officers will actually receive. The 2017 amounts represent payments which were earned in 2017 and paid in early 2018 and the 2016 amounts represent the payments which were earned in 2016 and paid in early 2017. For an explanation of the 2018 annual incentive plan awards, read Compensation Discussion and Analysis – 2018 Compensation Structure and Decisions Link Direct Compensation Elements to Strategy and Outcomes – Performance-Based Annual Incentive Program (AIP), contained within Anadarko's proxy statement for its 2019 annual meeting of stockholders, which is expected to be filed no later than April 4, 2019.

(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, 2018, 2017 and 2016. Ms. Fielder's amount reflects allocated expenses beginning November 15, 2018, the date of her appointment as President. Ms. Kelly's amount reflects allocated expenses beginning May 13, 2018, the date of her appointment as the principal operating officer. The 2018 allocated expenses are detailed in the table below:

Name	Retirement Plans Expense	Savings Plans Expense
Benjamin M. Fink	$ 59,371	$43,200
Jaime R. Casas	51,501	37,528
Robin H. Fielder	3,385	2,520
Gennifer F. Kelly	16,637	12,037
Philip H. Peacock	24,922	18,162

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Grants of Plan-Based Awards in 2018

The following table sets forth information concerning annual incentive awards, stock options, phantom units, shares of restricted stock, restricted stock units and performance units granted during 2018 to each of the named executive officers under the Omnibus Plan. 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.

Name and Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards [(1)] Threshold ($)	Target ($)	Maximum ($)	Estimated Future Payouts Under Equity Incentive Plan Awards [(2)] Threshold (#)	Target (#)	Maximum (#)	All Other Stock Awards: Number of Shares of Stock or Units (#) [(3)]	All Other Option Awards: Number of Securities Underlying Options (#) [(4)]	Exercise or Base Price of Option Awards ($/Sh)	Grant Date Fair Value of Stock and Option Awards ($) [(5)]
Benjamin M. Fink										
—	—	322,620	387,144							
11/15/18								37,420	55.51	578,038
11/15/18				7,732	19,330	38,660				1,180,676
11/15/18							10,864			603,061
Jaime R. Casas										
—	—	226,575	271,890							
11/15/18								25,412	55.51	392,547
11/15/18				3,001	7,502	15,004				458,222
11/15/18							5,270			292,538
11/15/18							16,214			900,039
Robin H. Fielder										
—	—	17,761	21,313							
11/15/18								13,032	55.51	201,309
11/15/18				1,539	3,847	7,694				234,975
11/15/18							2,702			149,988
Gennifer F. Kelly										
—	—	72,753	87,303							
03/13/18							1,336			78,223
05/07/18							3,788			250,008
11/15/18								6,516	55.51	100,655
11/15/18				770	1,924	3,848				117,518
11/15/18							1,352			75,050
Philip H. Peacock										
—	—	109,625	131,550							
11/15/18								7,602	55.51	117,430
11/15/18				898	2,244	4,488				137,064
11/15/18							1,577			87,539

(1) Reflects the estimated 2018 cash payouts allocable to us under Anadarko's annual incentive plan. If threshold levels of performance are not met, then the payout can be zero. The maximum value reflects the maximum amount

allocable to us consistent with the methodologies set forth in the services and secondment agreement. The expense expected to be allocated to us for the actual bonus payouts under the annual incentive program for 2018 is reflected in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table. For additional discussion of Anadarko’s annual incentive plan, read Compensation Discussion and Analysis – 2018 Compensation Structure and Decisions Link Direct Compensation Elements to Strategy and Outcomes – Performance-Based Annual Incentive Program (AIP) contained within Anadarko’s proxy statement for its 2019 annual meeting of stockholders, which is expected to be filed no later than April 4, 2019.

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(2) Reflects the estimated future payout allocable to us under Anadarko's performance units awarded in 2018. Under the performance unit program, participants may earn from 0% to 200% of the targeted award based on Anadarko's relative total shareholder return performance over a three-year performance period. If earned, the awards are to be paid in cash rather than equity. The threshold value represents the minimum payment (other than zero) that may be earned. For additional discussion of Anadarko's performance unit awards, read Compensation Discussion and Analysis – 2018 Compensation Structure and Decisions Link Direct Compensation Elements to Strategy and Outcomes – Equity Compensation contained within Anadarko's proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 4, 2019.

(3) Reflects the allocable number of shares of restricted stock and restricted stock units awarded in 2018 under the Omnibus Plan. Generally speaking, these awards vest ratably on each of the first three anniversaries of the grant date. For shares of restricted stock, dividends are paid at the same time as dividends are paid with respect to outstanding shares of Anadarko common stock. For restricted stock units, dividend equivalents are reinvested in shares of Anadarko common stock and paid upon the applicable vesting of the underlying award. In addition to the annual grants in November 2018, Ms. Kelly received shares of restricted stock on March 13, 2018, prior to her appointment as an officer, and restricted stock units on May 7, 2018, in connection with her promotion and appointment as the principal operating officer; both grants vest ratably on each of the first three anniversaries of the grant date. Also included are the allocated 16,214 special restricted stock units awarded under the Omnibus Plan to Mr. Casas in 2018, which will fully vest four years from the grant date, provided Mr. Casas remains employed by Anadarko until such date.

(4) Reflects the allocable number of Anadarko stock options each named executive officer was awarded in 2018. Generally, these awards vest ratably on each of the first three anniversaries of the grant date and have a term of seven years.

(5) The amounts included in the Grant Date Fair Value of Stock and Option Awards column represent the expected allocation to us of the grant date fair value of the awards made to named executives in 2018 computed in accordance with FASB ASC Topic 718. The value ultimately realized by the executive upon the actual vesting of the award(s) or the exercise of the stock option(s) may or may not be equal to the determined value. For a discussion of valuation assumptions for the awards under the Omnibus Plan, see Note 23—Share-Based Compensation in the Notes to Consolidated Financial Statements under Part II, Item 8 of Anadarko's Form 10-K for the year ended December 31, 2018 (which is not, and shall not be deemed to be, incorporated by reference herein).

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Outstanding Equity Awards at Year-End 2018

The following table reflects outstanding equity awards as of December 31, 2018, for each of the named executive officers, including awards under Anadarko's Omnibus Plan. As of December 31, 2018, none of our named executive officers have any outstanding WES LTIP or WGP LTIP awards. The market values shown are based on Anadarko's closing stock price of $43.84 on December 31, 2018, unless otherwise noted. Except for amounts in the column entitled Option Exercise Price, the dollar amounts and number of securities included in the table below reflect an allocation based upon each officer's estimated allocation of time to Partnership business during the fiscal year ended December 31, 2018.

					Stock Awards			
	Option Awards (1) Number of Securities Underlying Unexercised Options				Restricted Stock Shares/Units (2)		Equity Incentive Plan Awards Performance Units (3)	
Name	Exercisable (#)	Unexercisable (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Market Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
Benjamin M. Fink								
06/07/13	1,298	—	87.98	06/07/20	—	—	—	—
11/06/13	5,412	—	92.02	11/06/20	—	—	—	—
11/06/14	13,235	—	93.51	11/06/21	—	—	—	—
10/26/15	18,035	—	69.00	10/26/22	—	—	—	—
10/26/15	—	—	—	—	—	—	3,101	135,948
11/10/16	—	—	—	—	13,293	582,765	—	—
11/10/16	—	—	—	—	—	—	3,450	151,248
11/10/16	11,549	5,774	61.87	11/10/23	—	—	—	—
11/10/16	—	—	—	—	1,385	60,718	—	—
02/13/17	3,087	6,173	68.14	02/13/24	—	—	—	—
02/13/17	—	—	—	—	1,508	66,111	—	—
02/13/17	—	—	—	—	—	—	1,867	81,849
11/14/17	—	—	—	—	7,818	342,741	—	—
11/14/17	17,213	34,424	48.05	11/14/24	—	—	—	
11/14/17	—	—	—	—	—	—	26,619	1,166,977
11/15/18	—	—	—	—	—	—	19,330	847,427
11/15/18	—	—	—	—	10,938	479,522	—	—
11/15/18	—	37,420	55.51	11/15/25	—	—	—	—
Jaime R. Casas								
05/22/17	—	29,174	53.35	05/22/24	—	—	—	—

05/22/17	—	—	—	—	9,478	415,516	—	—
11/14/17	—	—	—	—	4,138	181,410	—	—
11/14/17	9,109	18,216	48.05	11/14/24	—	—	—	—
11/14/17	—	—	—	—	—	—	14,088	617,618
11/15/18	—	—	—	—	—	—	7,502	328,888
11/15/18	—	—	—	—	5,306	232,615	—	—
11/15/18	—	—	—	—	16,325	715,688	—	—
11/15/18	—	25,412	55.51	11/15/25	—	—	—	—

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Robin H. Fielder								
04/12/16	—	—	—	—	262	11,486	—	—
11/10/16	—	—	—	—	—	—	618	27,093
11/10/16	2,069	1,034	61.87	11/10/23	—	—	—	—
11/10/16	—	—	—	—	248	10,872	—	—
05/22/17	—	—	—	—	5,745	251,861	—	—
11/14/17	—	—	—	—	796	34,897	—	—
11/14/17	1,752	3,503	48.05	11/14/24	—	—	—	—
11/14/17	—	—	—	—	—	—	2,709	118,763
11/15/18	—	—	—	—	—	—	3,847	168,652
11/15/18	—	—	—	—	2,721	119,289	—	—
11/15/18	—	13,032	55.51	11/15/25	—	—	—	—
Gennifer F. Kelly								
04/12/16	—	—	—	—	616	27,005	—	—
03/15/17	—	—	—	—	884	38,755	—	—
03/13/18	—	—	—	—	1,336	58,570	—	—
05/07/18	—	—	—	—	3,841	168,389	—	—
11/15/18	—	—	—	—	—	—	1,924	84,348
11/15/18	—	—	—	—	1,361	59,666	—	—
11/15/18	—	6,516	55.51	11/15/25	—	—	—	—
Philip H. Peacock								
04/12/16	—	—	—	—	666	29,197	—	—
03/27/17	1,788	3,575	59.94	03/27/24	—	—	—	—
03/27/17	—	—	—	—	—	—	1,033	45,287
03/27/17	—	—	—	—	852	37,352	—	—
11/14/17	—	—	—	—	10,606	464,967	—	—
11/14/17	—	—	—	—	1,150	50,416	—	—
11/14/17	2,531	5,060	48.05	11/14/24	—	—	—	—
11/14/17	—	—	—	—	—	—	3,913	171,546
11/15/18	—	—	—	—	—	—	2,244	98,377
11/15/18	—	—	—	—	1,588	69,618	—	—
11/15/18	—	7,602	55.51	11/15/25	—	—	—	—

(1) Stock options have a seven-year term and will vest ratably over three years in equal installments on the first, second, and third anniversaries of the date of grant. Stock option awards do not accrue dividends or dividend equivalents.

(2) Generally, the restricted stock units and shares of restricted stock will vest ratably over three years in equal installments on the first, second, and third anniversaries of the grant date. At the end of each vesting period, unless deferred, the number of restricted stock units that vest are settled in shares of unrestricted Anadarko common stock, less applicable withholding taxes. For shares of restricted stock, dividends are paid at the same time as dividends are paid with respect to outstanding shares of Anadarko common stock. For restricted stock units, dividend equivalents are accrued and reinvested in additional shares of common stock, less applicable withholding taxes. The following outstanding allocated special restricted stock units, including their corresponding dividend equivalent units, will fully vest four years from their respective grant dates, provided Messrs. Fink, Casas and Peacock and Ms. Fielder remain employed by Anadarko until such dates: 13,293 for Mr. Fink, 16,325 for Mr. Casas, 5,745 for Ms. Fielder and 10,606 for Mr. Peacock; these numbers include their corresponding dividend equivalent units as of December 31, 2018 and the actual number of shares that vest may differ from these values.

(3) The number of outstanding units and the estimated payout percentages disclosed for each award are calculated based on Anadarko's relative performance ranking as of December 31, 2018, and are not necessarily indicative of

what the payout percent earned will be at the end of each three-year performance period. The three-year performance period generally starts in January following the year of grant, however the February 2017 grant to Mr. Fink and the March 2017 grant to Mr. Peacock uses the performance period of the November 2016 grant which is January 1, 2017 to December 31, 2019. Anadarko’s relative performance rankings as of December 31, 2018 were: 60% for the October 2015 grant, 60% for the November 2016 and February and March 2017 grants, and 164% for the November 2017 grant. For awards granted in November 2018 with a performance period beginning in 2019, target payout has been assumed.

Option Exercises and Stock Vested in 2018

The following table reflects Anadarko option awards exercised in 2018 and Anadarko stock awards and WGP LTIP phantom units that vested in 2018. The dollar amounts and number of securities included in the table below reflect an allocation based upon each officer's allocation of time to Partnership business.

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#) (1)	Value Realized on Exercise ($) (1)	Number of Shares Acquired on Vesting (#) (2)	Value Realized on Vesting ($) (2)
Benjamin M. Fink	—	—	7,140	400,811
Jaime R. Casas	—	—	2,053	111,678
Robin H. Fielder	—	—	1,063	61,559
Gennifer F. Kelly	—	—	1,347	81,019
Philip H. Peacock	—	—	2,007	118,672

(1) Shares acquired and values realized on exercise include options exercised in 2018. The amounts shown in the "Value Realized on Exercise" column represent the difference between the market price of Anadarko common stock at exercise and the applicable exercise price of such option(s). The actual value ultimately realized by the named executive officer may be more or less than the realized value calculated in the above table depending on the timing in which the named executive officer held or sold the stock associated with the exercise.

(2) Shares acquired and values realized on vesting reflect the taxable value to the named executive officer as of the date of the vesting in 2018 of shares of restricted stock or restricted stock units, performance units, or phantom units. For each named executive officer, the amount shown in the "Value Realized on Vesting" column represents the aggregate number of restricted stock units or shares of restricted stock held by such named executive officer that vested during 2018 multiplied by the market price of Anadarko common stock on the applicable vesting date(s). For shares of restricted stock or restricted stock units, the actual value ultimately realized by the named executive officer may be more or less than the value realized calculated in the above table depending on the timing in which the named executive officer held or sold the stock associated with the exercise or vesting occurrence.

Pension Benefits for 2018

Anadarko maintains both funded, tax-qualified defined benefit pension plans and unfunded nonqualified pension benefit plans. The nonqualified pension benefit plans are designed to provide for supplementary pension benefits due to limitations imposed by the Internal Revenue Code that restrict the amount of benefits payable under tax-qualified plans. Our named executive officers are eligible to participate in these plans. Under the omnibus agreement, a portion of the annual expense related to these plans is reimbursed by us to Anadarko. The allocated expense for each named executive officer is included in the All Other Compensation column of the Summary Compensation Table. We have not included a pension benefits table as Anadarko does not allocate expense to the Partnership upon an employee's retirement and the subsequent payment of benefits under such pension plans. For additional discussion of Anadarko's pension benefits, read Compensation Discussion and Analysis — Indirect Compensation Elements — Retirement Benefits contained within Anadarko's proxy statement for its 2019 annual meeting of stockholders, which is expected to be filed no later than April 4, 2019.

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Nonqualified Deferred Compensation for 2018

Anadarko maintains a deferred compensation plan and a savings restoration plan for a select group of management and highly compensated employees who have reached the applicable Internal Revenue Code contribution limitations, including our named executive officers. The deferred compensation plan allows certain employees to voluntarily defer receipt of up to 75% of their salary and/or up to 100% of their annual incentive bonus payments. The savings restoration plan accrues a benefit substantially equal to the amount that, in the absence of certain Internal Revenue Code limitations, would have been allocated to their account as matching contributions under Anadarko's 401(k) Plan. Pursuant to the terms of the omnibus agreement, a portion of the expense related to these plans is reimbursed by us to Anadarko. The allocated expense for each named executive officer is included in the All Other Compensation column of the Summary Compensation Table. We have not included a nonqualified deferred compensation table as Anadarko does not allocate expense to the Partnership upon distribution of such balances. For additional discussion on Anadarko's nonqualified deferred compensation benefits, read Compensation Discussion and Analysis — Indirect Compensation Elements — Other Benefits sections contained within Anadarko's proxy statement for its 2019 annual meeting of stockholders, which is expected to be filed no later than April 4, 2019.

Potential Payments Upon Termination or Change of Control

In the event of a Change of Control (as defined below) of the general partner, the only payments that we would be responsible for paying to our named executive officers relate to our allocated share of the accelerated vesting of unvested awards under the WES LTIP. Similarly, we would be responsible for paying our allocated share of any accelerated vesting of awards under the WGP LTIP if a Change of Control were to occur at WGP GP. As of December 31, 2018, none of our named executive officers have any outstanding WES LTIP or WGP LTIP awards. We have not entered into any employment agreements with our named executive officers, nor do we manage any severance plans. However, our named executive officers are eligible for certain benefits provided by Anadarko. Currently, we are not allocated any expense for these agreements or plans, but for disclosure purposes we are presenting hypothetical allocations of the potential payments to be made by Anadarko in the event of termination of the named executive officer or a Change of Control of Anadarko. For the definition of a Change of Control of Anadarko, read Executive Compensation - Potential Payments Upon Termination or Change of Control contained within Anadarko's proxy statement for its 2019 annual meeting of stockholders, which is expected to be filed no later than April 4, 2019. Values reflect each named executive officer's allocation of time to Partnership business at December 31, 2018, and exclude those benefits generally provided to all salaried employees. For additional discussion related to these termination scenarios, read Compensation Discussion and Analysis — Indirect Compensation Elements — Severance Benefits contained within Anadarko's proxy statement for its 2019 annual meeting of stockholders, which is expected to be filed no later than April 4, 2019.
The following tables reflect the expenses that could be allocated to the Partnership by Anadarko as of December 31, 2018, in connection with potential payments to our named executive officers under existing contracts, agreements, plans or arrangements, whether written or unwritten, with Anadarko, for various scenarios involving a Change of Control of Anadarko or termination of employment from Anadarko for each named executive officer, assuming a termination date of December 31, 2018, and, where applicable, using the closing price of Anadarko's common stock of $43.84 (as reported on the NYSE as of December 31, 2018). For general definitions that apply to the termination of employment from Anadarko scenarios detailed below, read Executive Compensation - Potential Payments Upon Termination or Change of Control contained within Anadarko's proxy statement for its 2019 annual meeting of stockholders, which is expected to be filed no later than April 4, 2019. Actual amounts will be determinable only upon the termination or Change in Control event.

Involuntary For Cause

	Mr. Fink	Mr. Casas	Ms. Fielder	Ms. Kelly	Mr. Peacock

Cash Severance	$ —$	—$	—$	—$	—
Total	$ —$	—$	—$	—$	—

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Voluntary Termination (Including Retirement)

	Mr. Fink	Mr. Casas	Ms. Fielder	Ms. Kelly	Mr. Peacock
Continued Vesting of Option Awards (1)	$ —	$ —	$ —	$ —	$ —
Payout of Performance Unit Awards (2)	—	—	—	—	—
Continued Vesting of Restricted Stock Unit Awards (3)	—	—	—	—	—
Total	$ —	$ —	$ —	$ —	$ —

(1) Reflects the value (determined as the excess, if any, of the fair market value of a share as of December 31, 2018, over the exercise price of such share (the "in-the-money value")) of allocated unvested stock options. The nonqualified stock option agreements provide for continued vesting according to the time-based vesting schedule in cases of qualified retirement (which means retirement at or after age 60 with minimum 10 years of service). As of December 31, 2018, none of our named executive officers were eligible for qualified retirement.

(2) Under the terms of the performance unit agreements, retirement-eligible participants, as defined by the Anadarko Petroleum Corporation Retiree Health Benefits Plan, receive a prorated payout, paid after the end of the performance period, based on actual performance and the number of months worked during the performance period. Additionally, the performance unit agreements provide for payout at the end of the performance period, with no proration and based on actual performance, in cases of a qualified retirement, or retirement at or after age 60 with minimum 10 years of service. As of December 31, 2018, none of our named executive officers were eligible for retirement nor qualified retirement.

(3) Under the terms of the restricted stock unit agreements, in the event of a qualified retirement, restricted stock units will be settled according to the vesting schedule. As of December 31, 2018, none of our named executive officers were eligible for qualified retirement.

Involuntary Not For Cause Termination

	Mr. Fink	Mr. Casas	Ms. Fielder	Ms. Kelly	Mr. Peacock
Cash Severance (1)	$1,482,375	$965,925	$407,400	$430,625	$496,875
Pro-rata Bonus (2)	387,144	271,890	21,313	87,303	131,550
Accelerated Anadarko Equity Awards (3)	3,779,358	2,491,735	742,913	436,733	966,760
Supplemental Pension Benefits (4)	—	—	—	—	—
Medical and Dental (5)	8,828	9,882	2,450	7,790	5,490
Total	$5,657,705	$3,739,432	$1,174,076	$962,451	$1,600,675

(1) The values assume two times base salary plus one times target AIP bonus. All values reflect each named executive officer's estimated allocation percentage during the fiscal year ended December 31, 2018.

(2) Payment, if provided, will be paid at the end of the performance period based on actual performance. The values reflect the allocated portion of our named executive officers' bonus awarded under the annual incentive plan. For additional discussion of this program, read Compensation Discussion and Analysis – 2018 Compensation Structure and Decisions Link Direct Compensation Elements to Strategy and Outcomes – Performance-Based Annual Incentive Program (AIP) of Anadarko's proxy statement for its 2019 annual meeting of stockholders, which is expected to be filed no later than April 4, 2019.

(3) Reflects the in-the-money value of unvested stock options (subject to Anadarko's Board of Directors approval of the acceleration of such stock options, as discussed below), the estimated current value of unvested performance units (based on performance to date) and the value of unvested shares of restricted stock and restricted stock units granted under the Omnibus Plan, all as of December 31, 2018. In the event of an involuntary termination, unvested performance units would be paid after the end of the applicable performance period, based on actual performance. Further, while the terms of the outstanding stock options do not require Anadarko to accelerate the vesting of the stock options upon an involuntary termination not for cause, Anadarko's Board of Directors has a historic practice

of doing so and, as such, the value of acceleration of the outstanding stock option awards is included above. The equity awards granted on and after November 10, 2016 contain a non-disclosure covenant (indefinite duration) and non-disparagement and employee non-solicitation covenants (one year). All values reflect each named executive officer's estimated allocation percentage during the fiscal year ended December 31, 2018.

(4) Reflects the lump-sum present value of additional benefits related to Anadarko's supplemental pension benefits which are contingent upon the termination event. The value includes special pension credits, provided through an employment agreement, retention agreement, the APC Retirement Restoration Plan or the KMG Restoration Plan, as applicable. The value of this benefit has not been included in this table as Anadarko does not allocate expense to the Partnership for distribution of these benefits. If Anadarko were to allocate this expense to the Partnership, assuming their allocation percentages in effect as of December 31, 2018, the expense would be as follows: Ms. Fielder—$111,430 and Ms. Kelly—$162,249.

(5) Values represent six months of medical and dental active employee rate benefit coverage. These amounts are present values determined in accordance with GAAP. These values reflect the applicable and estimated allocation percentages for each named executive officer during the fiscal year ended December 31, 2018.

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Change of Control: Involuntary Termination or Voluntary For Good Reason

	Mr. Fink	Mr. Casas	Ms. Fielder	Ms. Kelly	Mr. Peacock
Cash Severance (1)	$2,077,637	$959,580	$411,000	$468,990	$549,636
Pro-rata Bonus (2)	394,266	115,290	60,000	71,995	87,318
Accelerated Anadarko Equity Awards (3)	3,779,358	2,491,735	742,913	436,733	966,760
Supplemental Pension Benefits (4)	—	—	—	—	—
Nonqualified Deferred Compensation (5)	224,823	95,958	24,660	25,710	53,170
Health and Welfare Benefits (6)	85,042	55,112	13,341	36,185	27,770
Total	$6,561,126	$3,717,675	$1,251,914	$1,039,613	$1,684,654

(1) For Mr. Fink, the value assumes two and a half times the sum of base salary in effect at the end of 2018 and his target annual bonus for the year in which the date of termination occurs. For all other named executive officers, values assume two times the sum of base salary plus the highest bonus paid in the past three years, per the terms of the key employee change of control agreement with Anadarko. Mr. Casas' value was calculated using his bonus payout in 2018 since he did not receive bonus payouts in the prior two years. All values reflect the estimated allocation percentages during the fiscal year ended December 31, 2018.

(2) For Mr. Fink, the value assumes pro-rata bonus based on the target AIP bonus percentage in effect for the year of termination, base salary in effect at the beginning of the year and Anadarko's actual performance, as may be allocated under the Omnibus Agreement. For all other named executive officers, values assume the full-year equivalent of the applicable named executive officer's highest annual bonus allocated to us over the past three years. The value for Mr. Casas' highest annual bonus was based on the payout in 2018 as he did not receive bonus payouts in the prior two years. All values reflect the estimated allocation percentages during the fiscal year ended December 31, 2018.

(3) Reflects the in-the-money value of unvested stock options, the value of unvested shares of restricted stock and restricted stock units and the estimated current value of unvested performance units (based on performance to date) granted under the Omnibus Plan, all as of December 31, 2018. Upon a Change of Control, the value of unvested performance units would be calculated based on Anadarko's total shareholder return performance and stock price at the time of the Change of Control and converted into restricted stock units of the surviving company. In the event of an involuntary not for cause termination or voluntary for good reason termination within two years following a Change of Control, the units will generally be paid on the first business day that is at least six months and one day following the separation from service. In the event of an involuntary not for cause or voluntary for good reason termination that is more than two years following a Change of Control, the units will be paid at the end of the original performance period. The equity awards granted on and after November 10, 2016 contain a non-disclosure covenant (indefinite duration) and non-disparagement and employee non-solicitation covenants (one year). All values reflect each named executive officer's estimated allocation percentage during the fiscal year ended December 31, 2018.

(4) Under the terms of the change of control agreement, our named executive officers would receive a special retirement benefit enhancement that is equivalent to the additional supplemental pension benefits that would have accrued under Anadarko's retirement plan assuming the applicable named executive officer was eligible for subsidized early retirement benefits and include additional special pension credits. The value of this benefit has not been included in this table as Anadarko does not allocate expense to the Partnership for distribution of these benefits. If Anadarko were to allocate this expense to the Partnership, assuming the allocation percentages in effect as of December 31, 2018, the expense would be as follows: Mr. Fink—$304,226, Mr. Casas—$99,812, Ms. Fielder—$402,040, Ms. Kelly—$315,397, and Mr. Peacock—$50,809.

(5) For Mr. Fink, the values reflect an additional three years of employer contributions into the savings restoration plan at his current contribution rate to the plan and is based on his estimated allocation percentage during the fiscal year ended December 31, 2018. For all other named executive officers, the values reflect an additional two years of employer contributions into the savings restoration plan at their current contribution rate to the plan and are based on their estimated allocation percentages during the fiscal year ended December 31, 2018, per the terms of their

key employee change of control agreements with Anadarko.

(6) The values represent 36 months and 24 months of health and welfare benefit coverage for Mr. Fink and all other named executive officers, respectively. These amounts are present values determined in accordance with GAAP and reflect the estimated allocation percentages during the fiscal year ended December 31, 2018.

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Disability

	Mr. Fink	Mr. Casas	Ms. Fielder	Ms. Kelly	Mr. Peacock
Cash Severance	$—	$—	$—	$—	$—
Accelerated Anadarko Equity Awards (1)	3,779,358	2,491,735	742,913	436,733	966,760
Health and Welfare Benefits (2)	224,998	162,749	41,139	48,700	85,518
Total	$4,004,356	$2,654,484	$784,052	$485,433	$1,052,278

(1) Reflects the in-the-money value of unvested stock options, the value of unvested shares of restricted stock and restricted stock units and the estimated current value of unvested performance units (based on performance to date) granted under the Omnibus Plan, all as of December 31, 2018. In the event of a termination as a result of disability, performance units would be paid after the end of the applicable performance period, based on actual performance. The equity awards granted on and after November 10, 2016, contain a non-disclosure covenant (indefinite duration) and non-disparagement and employee non-solicitation covenants (one year). All values reflect each named executive officer's estimated allocation percentage during the fiscal year ended December 31, 2018.

(2) Values reflect the continuation of additional death benefit coverage provided to certain employees of Anadarko until age 65. All amounts are present values determined in accordance with GAAP and reflect each named executive officer's estimated allocation percentage during the fiscal year ended December 31, 2018.

Death

	Mr. Fink	Mr. Casas	Ms. Fielder	Ms. Kelly	Mr. Peacock
Cash Severance	$—	$—	$—	$—	$—
Accelerated Anadarko Equity Awards (1)	3,479,317	2,250,703	714,636	436,733	929,978
Life Insurance Proceeds (2)	1,657,049	1,201,979	479,802	535,862	618,302
Total	$5,136,366	$3,452,682	$1,194,438	$972,595	$1,548,280

(1) Reflects the in-the-money value of unvested stock options, the target value of unvested performance units, and the value of unvested shares of restricted stock and restricted stock units granted under the Omnibus Plan, all as of December 31, 2018. All values reflect each named executive officer's estimated allocation percentage during the fiscal year ended December 31, 2018.

(2) Values include amounts payable under additional death benefits provided to certain employees of Anadarko. These liabilities are not insured, but are self-funded by Anadarko. Proceeds are not exempt from federal taxes. Values shown include an additional tax gross-up amount to equate benefits with non-taxable life insurance proceeds. Values are based on each named executive officer's estimated allocation percentage during the fiscal year ended December 31, 2018, and exclude death benefit proceeds from programs available to all employees.

CEO Pay Ratio

Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and Item 402(u) of Regulation S-K, require disclosure regarding the relationship of the annual compensation of our employees and the annual compensation of Mr. Benjamin M. Fink, our Chief Executive Officer (CEO). As discussed in the Employees section in Business and Properties under Part I, Items 1 and 2 of this form 10-K, we have no employees. Nonetheless, in an effort to comply with this requirement, the pay ratio provided below has been calculated as the total 2018 annual compensation for Mr. Fink, divided by the total annual compensation of the median employee providing services to the Partnership pursuant to (i) the Services and Secondment Agreement and (ii) the Omnibus Agreement, in each case on an unallocated (100%) basis. For 2018, the ratio resulting from this calculation was 27 to 1.

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Director Compensation

Officers or employees of Anadarko who also serve as directors of our general partner do not receive additional compensation for their service as a director of our general partner. Non-employee directors of our general partner receive compensation for their board service and for attending Board and committee meetings pursuant to a director compensation plan approved by the Board of Directors. There were no changes to the director compensation plan during 2018. Such compensation consists of the following:

- an annual retainer of $110,000 for each non-employee Board member;
- an annual retainer of $2,000 for each member of the Audit Committee, or $22,000 for the Audit Committee chair;
- an annual retainer of $2,000 for each member of the Special Committee, or $22,000 for the Special Committee chair;
- a fee of $2,000 for each Board and committee meeting attended to the extent a non-employee Board member attends in excess of 10 total Board and committee meetings in one calendar year; and
- annual grants of phantom units with a value of approximately $100,000 on the date of grant, all of which vest 100% on the first anniversary of the date of grant (with vesting to be accelerated upon a change of control of our general partner or Anadarko).

In addition, each non-employee director is reimbursed for out-of-pocket expenses in connection with attending meetings of the Board of Directors or committees and for costs associated with participation in continuing director education programs. Each director is fully indemnified by us, pursuant to individual indemnification agreements and our partnership agreement, for actions associated with being a director to the fullest extent permitted under Delaware law.

The following table sets forth information concerning total director compensation earned during 2018 by each non-employee director:

Name	Fees Earned or Paid in Cash	Stock Awards [1]	Option Awards	Non-Equity Incentive Plan Compensation	All Other Compensation	Total
Steven D. Arnold	$ 120,000	$ 100,009	$ —	$ —	$ —	$ 220,009
Milton Carroll	132,000	100,009	—	—	—	232,009
James R. Crane	120,000	100,009	—	—	—	220,009
David J. Tudor	132,000	100,009	—	—	—	232,009

(1) The amounts included in the Stock Awards column represent the grant date fair value of non-option awards made to directors in 2018, computed in accordance with FASB ASC Topic 718. For a discussion of valuation assumptions, see Note 6—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K. As of December 31, 2018, each of the non-employee directors held 2,005 outstanding phantom units.

The following table contains the grant date fair value of phantom unit awards made to each non-employee director during 2018:

Name	Grant Date	Phantom Units (#)	Grant Date Fair Value of Stock and Option Awards ($) [1]
Steven D. Arnold	May 8	2,005	100,009

Milton Carroll	May 8	2,005	100,009
James R. Crane	May 8	2,005	100,009
David J. Tudor	May 8	2,005	100,009

(1) The amounts included in the Grant Date Fair Value of Stock and Option Awards column represent the grant date fair value of the awards made to non-employee directors in 2018 computed in accordance with FASB ASC Topic 718. The value ultimately realized by a director upon the actual vesting of the award(s) may or may not be equal to the value included above.

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Compensation Committee Interlocks and Insider Participation

As previously discussed, our Board of Directors is not required to maintain, and does not maintain, a compensation committee. Ms. Fielder and Messrs. Brown, Fink, Gwin, and Ingram, who are directors of our general partner, are also executive or corporate officers of Anadarko. However, all compensation decisions with respect to each of these persons are made by Anadarko and none of these individuals receive any compensation directly from us or our general partner for their service as directors. Read Part III, Item 13 below in this Form 10-K for information about relationships among us, our general partner and Anadarko.

Compensation Committee Report

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

The Board of Directors of Western Gas Holdings, LLC:

Benjamin M. Fink
Robin H. Fielder
Robert G. Gwin
Steven D. Arnold
Daniel E. Brown
Milton Carroll
James R. Crane
Mitch W. Ingram
David J. Tudor

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

The following table sets forth the beneficial ownership of our common units and WGP common units held by the following as of February 18, 2019:

- each member of the Board of Directors;
- each named executive officer of our general partner;
- all directors and officers of our general partner as a group; and
- Anadarko and its affiliates.

Name and Address of Beneficial Owner (1)	WES Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	WGP Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
Anadarko Petroleum Corporation (2)	52,143,426	34.17%	170,380,161	77.82%
Robert G. Gwin	5,000	*	100,000	*
Benjamin M. Fink	2,213	*	18,683	*
Jaime R. Casas	—	*	—	*
Robin H. Fielder	—	*	—	*
Gennifer F. Kelly	—	*	—	*
Philip H. Peacock	—	*	7,500	*
Steven D. Arnold (3)	37,938	*	7,500	*
Daniel E. Brown	—	*	—	*
Milton Carroll (3)	10,343	*	—	*
James R. Crane (3)	13,121	*	66,000	*
Mitchell W. Ingram	—	*	—	*
David J. Tudor (3)	12,519	*	8,463	*
All directors and executive officers as a group (12 persons)	81,134	*	208,146	*

*Less than 1%

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

(2) WGP held 50,132,046 common units and other subsidiaries of Anadarko, AMM and AMH, collectively held 2,011,380 common units. Anadarko is the ultimate parent company of WGRI, AMM, AMH and WGP GP and may, therefore, be deemed to beneficially own the units held by such parties. Anadarko, through AMH, also held 14,681,388 Class C units of the Partnership.

(3) Does not include 2,005 unvested phantom units that were granted to each of Messrs. Arnold, Carroll, Crane, and Tudor under the WES LTIP. Phantom units granted to the independent directors of WES vest 100% on the first anniversary of the date of the grant. Each vested phantom unit entitles the holder to receive a common unit or, in the discretion of our Board of Directors, cash equal to the fair market value of a common unit. Holders of phantom units are entitled to distribution equivalents on a current basis. Holders of phantom units have no voting rights until such time as the phantom units become vested and common units are issued to such holders.

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The following table sets forth the number of shares of common stock of Anadarko owned by each of the named executive officers and directors of our general partner and all directors and executive officers of our general partner as a group as of February 18, 2019:

Name and Address of Beneficial Owner [1]	Shares of Common Stock Owned Directly or Indirectly [2]	Shares Underlying Options Exercisable Within 60 Days [2]	Total Shares of Common Stock Beneficially Owned [2]	Percentage of Total Shares of Common Stock Beneficially Owned [2]
Robert G. Gwin [3] [4]	72,023	169,812	241,835	*
Benjamin M. Fink [3]	19,896	90,690	110,586	*
Jaime R. Casas [3]	1,726	10,121	11,847	*
Robin H. Fielder [3] [5]	4,502	12,734	17,236	*
Gennifer F. Kelly [3] [5]	9,616	—	9,616	*
Philip H. Peacock [3] [5]	2,442	12,210	14,652	*
Steven D. Arnold	4,900	—	4,900	*
Daniel E. Brown [3]	27,327	128,494	155,821	*
Milton Carroll	—	—	—	*
James R. Crane	—	—	—	*
Mitchell W. Ingram [3]	50,709	61,270	111,979	*
David J. Tudor	—	—	—	*
All directors and executive officers as a group (12 persons) [3]	193,141	485,331	678,472	*

*Less than 1%

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

(2) As of December 31, 2018, there were 499.6 million shares of Anadarko common stock outstanding.

(3) Does not include unvested restricted stock units of Anadarko held by the following individuals in the amounts indicated: Robert G. Gwin—45,166; Benjamin M. Fink—41,815; Jaime R. Casas—38,689; Robin H. Fielder—31,163; Gennifer F. Kelly—10,279; Philip H. Peacock—27,887; Daniel E. Brown—57,215; and Mitchell W. Ingram—43,948; for a total of 296,162 unvested restricted stock units held by the directors and executive officers as a group. Restricted stock units typically vest equally over three years beginning on the first anniversary of the date of grant, and upon vesting are payable in Anadarko common stock, subject to applicable tax withholding. Holders of restricted stock units receive dividend equivalents on the units, but do not have voting rights. Generally, a holder will forfeit any unvested restricted units if he or she terminates voluntarily or is terminated for cause prior to the vesting date. Holders of restricted stock units have the ability to defer such awards.

(4) In 2017, Mr. Gwin transferred the economic interest in certain stock options and restricted stock units of Anadarko common stock pursuant to a domestic relations order. The shares reported do not reflect the stock options or restricted stock units in which he has no economic or beneficial interest.

(5) Includes 872, 5,670 and 1,331 unvested shares of restricted common stock of Anadarko held by Robin H. Fielder, Gennifer F. Kelly and Philip H. Peacock, respectively. Restricted stock awards typically vest equally over three years beginning on the first anniversary of the date of grant. Holders of restricted stock receive dividends on the shares and also have voting rights. Generally, a holder of restricted stock will forfeit any unvested restricted shares if he or she terminates voluntarily or is terminated for cause prior to the vesting date.

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

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Units	Tortoise Capital Advisors, L.L.C. 11550 Ash Street Suite 300 Leawood, KS 66211	15,779,164 (1)	10.30%
Common Units	ALPS Advisors, Inc. 1290 Broadway, Suite 1100 Denver, CO 80203	9,954,452 (2)	5.97%
Common Units	Kayne Anderson Capital Advisors, L.P. 1800 Avenue of the Stars Third Floor Los Angeles, CA 90067	8,725,038 (3)	5.71%

(1) Based upon its Schedule 13G filed February 12, 2019, with the SEC with respect to Partnership securities held as of December 31, 2018, Tortoise Capital Advisors, L.L.C. has shared voting power as to 14,143,949 common units and shared dispositive power as to 15,658,185 common units and sole voting and dispositive power over 120,979 common units.

(2) Based upon its Schedule 13G filed February 4, 2019, with the SEC with respect to Partnership securities held as of December 31, 2018, ALPS Advisors, Inc. (“ALPS”) has shared voting and dispositive power as to 9,954,452 common units and Alerian MLP ETF, a fund controlled by ALPS, also has shared voting and dispositive power as to 9,954,452 of the common units held by ALPS.

(3) Based upon its Schedule 13G/A filed February 1, 2019, with the SEC with respect to Partnership securities held as of December 31, 2018, Kayne Anderson Capital Advisors, L.P. has shared voting and dispositive power as to 8,629,682 common units and Richard A. Kayne has sole voting and dispositive power over 95,356 common units.

Securities Authorized for Issuance Under Equity Compensation Plan

The following table sets forth information with respect to the securities that may be issued under the WES LTIP as of December 31, 2018. For more information regarding the WES LTIP, which did not require approval by our unitholders, read Note 6—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a))
Equity compensation plans approved by security holders	—	—	—

Equity compensation plans not approved by security holders	8,020	— (1)	2,241,980
Total	8,020	—	2,241,980

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

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

As of February 18, 2019, WGP held 50,132,046 common units, representing a 29.5% limited partner interest in us, 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 us, and 100% of the IDRs. As of February 18, 2019, other subsidiaries of Anadarko collectively held 2,011,380 common units and 14,681,388 Class C units, representing an aggregate 9.9% limited partner interest in us.

Distributions and Payments to Our General Partner, WGP and Other Subsidiaries of Anadarko

The following table summarizes the distributions and payments made by us to our general partner, WGP and other subsidiaries of Anadarko and to be made to us by our general partner, WGP and other subsidiaries of Anadarko in connection with our ongoing operation and liquidation. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Formation stage	
The consideration received by Anadarko for the contribution of the assets and liabilities to us	5,725,431 common units; 26,536,306 subordinated units; 1,083,115 general partner units, and our IDRs.
Operational stage	
Distributions of available cash to our general partner, WGP and other subsidiaries of Anadarko	We will generally make cash distributions to our unitholders pro rata, including WGP and other subsidiaries of Anadarko as the holders of 50,132,046 common units and 2,011,380 common units, respectively, and to our general partner as the holder of 2,583,068 general partner units. In addition, if distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner will be entitled to increasing percentages of the distributions, up to 50.0% of the distributions above the highest target distribution level. As of December 31, 2018, the general partner was entitled to a maximum distribution sharing percentage of 49.5%, which includes distributions paid on its 1.5% general partner interest and the 48.0% IDR maximum distribution sharing percentage. See Note 4—Partnership Distributions and Note 5—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.
Distributions of additional Class C units	In connection with the closing of the DBM acquisition in November 2014, we issued 10,913,853 Class C units. Class C units receive quarterly distributions at a rate equivalent to our common units. As of February 18, 2019, we have issued 3,767,535 PIK Class C units as quarterly distributions. For a further discussion of the Class C units, refer to Class C Unit Issuance below.
Payments to our general partner and its affiliates	Our general partner and its affiliates are entitled to reimbursement for expenses incurred on our behalf, including salaries and employee benefit costs for employees who provide services to us, and all other necessary or appropriate expenses allocable to us or reasonably incurred by our general partner and its affiliates in connection with operating our business. The partnership agreement provides that our general partner determines in good faith the amount of such expenses that are allocable to us.

Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its IDRs will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation stage	
Liquidation	Upon our liquidation, our partners, including our general partner, WGP and other subsidiaries of Anadarko, will be entitled to receive liquidating distributions according to their respective capital account balances.

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Agreements with Anadarko

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

Omnibus Agreement

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

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

- our obligation to reimburse Anadarko for expenses incurred or payments made on our behalf in conjunction with Anadarko's provision of general and administrative services to us, including salary and benefits of Anadarko personnel, our public company expenses, general and administrative expenses and salaries and benefits of our executive management who are employees of Anadarko (see Administrative services and reimbursement below for details regarding certain agreements for amounts reimbursed in 2018); and

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

The table below reflects the categories of expenses for which we were obligated to reimburse Anadarko pursuant to the omnibus agreement for the year ended December 31, 2018:

thousands	Year Ended December 31, 2018
Reimbursement of general and administrative expenses	$ 35,077
Reimbursement of public company expenses	15,409
Total reimbursement	$ 50,486

Any or all of the provisions of the omnibus agreement are terminable by Anadarko at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal. The omnibus agreement will also generally terminate in the event of a change of control of us or our general partner. See Note 6—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Administrative services and reimbursement. Under the omnibus agreement, we reimburse Anadarko for the payment of certain operating expenses and for the provision of various general and administrative services for our benefit with respect to the assets Anadarko contributed to us concurrently with the closing of our May 2008 IPO, consisting of the initial assets, and for subsequent acquisitions. The omnibus agreement further provides that we reimburse Anadarko for all expenses it incurs or payments it makes with respect to our assets.
Pursuant to these arrangements, Anadarko performs centralized corporate functions for us, such as legal; accounting; treasury; cash management; investor relations; insurance administration and claims processing; risk management; health, safety and environmental; information technology; human resources; credit; payroll; internal audit; tax; marketing and midstream administration. We reimburse Anadarko for expenses it incurs or payments it makes on our behalf, including salaries and benefits of Anadarko personnel, our public company expenses, our general and

administrative expenses and salaries and benefits of our executive management who are also employees of Anadarko. Under our partnership and omnibus agreements, we reimburse Anadarko for general and administrative expenses allocated, as determined by Anadarko in its reasonable discretion.

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Indemnification with respect to initial assets. Under the omnibus agreement, Anadarko agreed to indemnify us against certain environmental, title and operation matters associated with our initial assets. We have claimed no indemnities under the omnibus agreement prior to the date hereof. Other than with respect to certain tax liabilities attributable to assets or liabilities retained by Anadarko, the indemnification obligations under the omnibus agreement have expired.

Indemnification Agreements with Directors and Officers

Our general partner entered into indemnification agreements with each of its officers and directors (each, an Indemnitee). Each indemnification agreement provides that our general partner will indemnify and hold harmless each Indemnitee against all expense, liability and loss (including attorney's fees, judgments, fines or penalties and amounts to be paid in settlement) actually and reasonably incurred or suffered by the Indemnitee in connection with serving in their capacity as officers and directors of our general partner (or of any subsidiary of our general partner) or in any capacity at the request of our general partner or its Board of Directors to the fullest extent permitted by applicable law, including Section 18-108 of the Delaware Limited Liability Company Act in effect on the date of the agreement or as such laws may be amended to provide more advantageous rights to the Indemnitee. The indemnification agreements also provide that our general partner must advance payment of certain expenses to the Indemnitee, including fees of counsel, in advance of final disposition of any proceeding subject to receipt of an undertaking from the Indemnitee to return such advance if it is ultimately determined that the Indemnitee is not entitled to indemnification.
Through December 31, 2018, there have been no payments or claims to Anadarko related to indemnifications and no payments or claims have been received from Anadarko related to indemnifications.

Services and Secondment Agreement

In connection with our IPO, Anadarko and our general partner entered into a services and secondment agreement, pursuant to which specified employees of Anadarko are seconded to our general partner to provide operating, routine maintenance and other services with respect to the assets we own and operate under the direction, supervision and control of our general partner. Pursuant to the services and secondment agreement, we reimburse Anadarko for services provided by the seconded employees. The initial term of the services and secondment agreement expired in May 2018, but was extended for a twelve-month period and will continue to automatically extend for additional twelve-month periods unless either party provides 180 days written notice of termination before the applicable twelve-month period expires.

Tax Sharing Agreement

In connection with our IPO, we entered into a tax sharing agreement pursuant to which we reimburse Anadarko for our estimated share of taxes from all forms of taxation, excluding taxes imposed by the United States. Taxes for which we reimburse Anadarko include state taxes attributable to our 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 our acquisition of the Partnership assets, which refers to the assets owned and interests accounted for under the equity method by us as of December 31, 2018. Anadarko may use its own tax attributes to reduce or eliminate the tax liability of its combined or consolidated group, which may include us as a member. However, under this circumstance, we nevertheless are required to reimburse Anadarko for our allocable share of taxes that would have been owed had tax attributes not been available to Anadarko.

Related-Party Acquisition Agreements

In connection with the acquisition of assets from Anadarko, we regularly enter into contribution or purchase and sale agreements with Anadarko and its affiliates. These agreements typically provide for payment by us to Anadarko of a purchase price in the form of cash and issuance of common units.

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

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The Board of Directors approved the acquisition of the Partnership assets from Anadarko, based in part on the recommendations in favor of the acquisitions from, and the granting of special approval under our partnership agreement by, the Board's Special Committee. The Special Committee, a committee of independent members of our Board of Directors, retains independent legal and financial advisors to assist it in evaluating and negotiating the acquisitions as it deems necessary on a transaction-by-transaction basis.

Chipeta LLC Agreement

In connection with the acquisition of our interest in Chipeta, we became party to the Chipeta LLC agreement, together with a third-party member. Among other things, the Chipeta LLC agreement provides the following:

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

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

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

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

Commodity Price Swap Agreements

Prior to their expiration on December 31, 2018, we had commodity price swap agreements with Anadarko to mitigate exposure to commodity price risk inherent in our percent-of-proceeds, percent-of-product and keep-whole contracts. See Note 6—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Gathering and Processing Agreements

We have significant gathering and processing arrangements with affiliates of Anadarko on a majority of our systems. For the year ended December 31, 2018, 7% of our natural gas gathering, treating and transportation throughput and 41% of our natural gas processing throughput, was attributable to production owned or controlled by Anadarko, in each case exclusive of its equity investment throughput. For the year ended December 31, 2018, 73% of our crude oil, NGLs and produced water gathering, treating, transportation and disposal throughput was attributable to production owned or controlled by Anadarko, exclusive of its equity investment throughput.

Commodity Purchase and Sale Agreements

We sell a significant amount of our natural gas, condensate and NGLs to AESC, Anadarko's marketing affiliate that acts as an agent in the sale to a third party. In addition, we purchase natural gas, condensate and NGLs from AESC pursuant to purchase agreements. Our purchase and sale agreements with AESC are generally one-year contracts, subject to annual renewal.

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Class C Unit Issuance

As discussed above, we issued 10,913,853 Class C units to AMH, a subsidiary of Anadarko, at a price of $68.72 per unit, pursuant to the Unit Purchase Agreement with Anadarko and AMH. All outstanding Class C units will convert into our common units on a one-for-one basis immediately prior to the closing of the Merger, if consummated. If the Merger is not consummated, the conversion will occur on March 1, 2020, unless we elect to convert such units earlier or Anadarko extends the conversion date. 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. The distributions that Class C units receive are paid in the form of additional PIK Class C units, and the Class C units are disregarded with respect to distributions of 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 our common units for the ten days immediately preceding the payment date for the common unit distribution, less a 6% discount. As of February 18, 2019, 3,767,535 PIK Class C units have been issued as quarterly distributions. The terms of the Class C unit issuance were unanimously approved by the Board of Directors and by the Board's Special Committee. For more information, see Note 5—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Affiliate Asset Contributions and Distributions

The following table summarizes Anadarko's contributions and distributions of other assets to us:

	Year Ended December 31,					
	2018	2017	2016	2018	2017	2016
thousands	Purchases			Sales		
Cash consideration	$(254)	$(3,910)	$(3,965)	$—	$—	$623
Net carrying value	254	5,283	3,366	—	—	(605)
Partners' capital adjustment	$—	$1,373	$(599)	$—	$—	$18

Contributions in Aid of Construction Costs from Affiliates

On certain of our capital projects, Anadarko is obligated to reimburse us 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. For periods prior to January 1, 2018, the cash receipts resulting from such reimbursements were presented as "Contributions in aid of construction costs from affiliates" within the investing section of the consolidated statements of cash flows. As discussed in Recently adopted accounting standards in Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K, upon adoption of Topic 606, affiliate reimbursements of capital costs are reflected as contract liabilities upon receipt, amortized to Service revenues – fee based over the expected period of customer benefit, and presented within the operating section of the consolidated statements of cash flows.

Indemnification Agreements

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 our general partner for our long-term debt and/or borrowings under the RCF.

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Merger Transactions

On November 7, 2018, WGP, the Partnership, Anadarko and certain of their affiliates entered into a Contribution Agreement and Agreement and Plan of Merger (as may be amended from time to time, the “Merger Agreement”), pursuant to which, among other things, Clarity Merger Sub, LLC, a wholly owned subsidiary of WGP, will merge with and into the Partnership, with the Partnership continuing as the surviving entity and a subsidiary of WGP (the “Merger”). Upon closing of the Merger, which is expected to occur in the first quarter of 2019, the common units of the Partnership will no longer be publicly traded and will cease to trade on the NYSE under the symbol “WES.” The common units of WGP will begin trading on the NYSE under the symbol “WES” and WGP will change its name to Western Midstream Partners, LP.

The Merger Agreement also provides that WGP, the Partnership and Anadarko will, and will cause their respective affiliates to, cause the following transactions, among others, to occur immediately prior to the Merger becoming effective in the order as follows: (1) Anadarko E&P Onshore LLC and WGR Asset Holding Company LLC (“WGRAH”) (the “Contributing Parties”) will contribute to the Partnership all of their interests in each of Anadarko Wattenberg Oil Complex LLC, Anadarko DJ Oil Pipeline LLC, Anadarko DJ Gas Processing LLC, Wamsutter Pipeline LLC, DBM Oil Services, LLC, Anadarko Pecos Midstream LLC, Anadarko Mi Vida LLC and APC Water Holdings 1, LLC (“APCWH”) to WGR Operating, LP, Kerr-McGee Gathering LLC and Delaware Basin Midstream, LLC (each wholly owned by the Partnership) in exchange for aggregate consideration of $1.814 billion in cash from the Partnership, minus the outstanding amount payable pursuant to an intercompany note (“APCWH Note Payable”) to be assumed by the Partnership in connection with the transaction, and 45,760,201 of our common units; (2) AMH will sell to the Partnership its interests in Saddlehorn Pipeline Company, LLC and Panola Pipeline Company, LLC in exchange for aggregate consideration of $193.9 million in cash; (3) the Partnership will contribute cash in an amount equal to the outstanding balance of the APCWH Note Payable immediately prior to the effective time to APCWH, and APCWH will pay such cash to Anadarko in satisfaction of the APCWH Note Payable; (4) Class C units will convert into our common units on a one-for-one basis; and (5) the Partnership and its general partner will cause the conversion of the IDRs and the 2,583,068 general partner units held by the general partner into a non-economic general partner interest in us and 105,624,704 of our common units. The 45,760,201 of our common units to be issued to the Contributing Parties, less 6,375,284 common units to be retained by WGRAH, will be converted into the right to receive an aggregate of 55,360,984 WGP common units upon the consummation of the Merger.

See Note 13—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for additional information.

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Summary of Affiliate Transactions

Revenues from affiliates include amounts earned by us from services provided to Anadarko as well as from the sale of residue and NGLs to Anadarko. In addition, we purchase natural gas from an affiliate of Anadarko pursuant to gas purchase agreements. Operating and maintenance expense includes amounts accrued for or paid to affiliates for the operation of our assets, whether in providing services to affiliates or to third parties, including field labor, measurement and analysis, and other disbursements. A portion of our general and administrative expenses is paid by Anadarko, which results in affiliate transactions pursuant to the reimbursement provisions of the 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.
The following table summarizes material affiliate transactions (see Note 6—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K):

	Year Ended December 31,		
thousands	2018	2017	2016
Revenues and other [1]	$ 1,067,860	$ 1,365,318	$ 1,228,232
Equity income, net – affiliates [1]	153,024	85,194	78,717
Cost of product [1]	193,663	86,010	80,455
Operation and maintenance [2]	98,769	72,489	72,330
General and administrative [3]	45,359	39,130	38,066
Operating expenses	337,791	197,629	190,851
Interest income [4]	16,900	16,900	16,900
Interest expense [5]	—	71	(7,747)
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]	514,906	452,777	382,711
Above-market component of swap agreements with Anadarko [9]	51,618	58,551	45,820

(1) Represents amounts earned or incurred on and subsequent to the date of 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.

(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 acquisition of Partnership assets, as well as a management services fee for expenses incurred by Anadarko for periods prior to the acquisition of Partnership assets by us. These amounts include equity-based compensation expense allocated to us by Anadarko and amounts charged by Anadarko under the omnibus agreement. See Note 6—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

(4) Represents interest income recognized on the note receivable from Anadarko.

(5) Includes amounts related to the Deferred purchase price obligation - Anadarko. See Note 3—Acquisitions and Divestitures and Note 13—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

(6) Represents the cash payment to Anadarko for the settlement of the Deferred purchase price obligation - Anadarko. See Note 3—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

(7) Represents proceeds from the issuance of 835,841 common units to WGP as partial funding for the acquisition of Springfield. See Note 3—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

(8) Represents distributions paid under the partnership agreement. See Note 4—Partnership Distributions and Note 5—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

(9) See Note 6—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for more information.

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Other

In 2018, Anadarko made payments totaling approximately $688,000 to the Houston Astros Baseball Club. James R. Crane, a member of the Board of Directors, is the principal owner and Chairman of the Houston Astros.

Conflicts of Interest

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

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us and our limited partners, on the other hand, our general partner will resolve the conflict. Our partnership agreement contains provisions that modify and limit our general partner’s default state law fiduciary duties to our unitholders. Our partnership agreement also restricts the remedies available to our unitholders for actions taken by our general partner that, without those limitations, might constitute breaches of fiduciary duties otherwise applicable under state law. See Special Committee under Part III, Item 10 of this Form 10-K.

Our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our unitholders if the resolution of the conflict is any of the following:

- approved by the Special Committee of our general partner, although our general partner is not obligated to seek such approval;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

Our general partner may, but is not required to, seek the approval of such resolution from the Special Committee of its Board of Directors. In connection with a situation involving a conflict of interest, any determination by our general partner involving the resolution of the conflict of interest must be made in good faith, provided that, if our general partner does not seek approval from the Special Committee and its Board of Directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth bullet points above, then it will be presumed that, in making its decision, the Board of Directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the Partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the Special Committee may consider any factors that it determines in good faith to be appropriate when resolving a conflict. Our partnership agreement provides that for someone to act in good faith, that person must reasonably believe he is acting in the best interests of the Partnership.

Additionally, the Board of Directors has adopted a written Code of Business Conduct and Ethics (the “Code”), under which all directors and officers of the general partner, and employees working on our behalf, are expected to avoid conflicts or the appearance of conflicts in relation to their duties and responsibilities to us, and report any violation of the Code by any person. Under our Corporate Governance Guidelines, any waivers of the Code for any officer or director may only be made by the Board of Directors or by a committee of the Board of Directors composed of independent directors.

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Item 14. Principal Accounting Fees and Services

We have engaged KPMG LLP as our independent registered public accounting firm. The following table presents fees for the audit of the Partnership's annual consolidated financial statements for the last two fiscal years and for other services provided by KPMG LLP:

thousands	2018	2017
Audit fees	$1,860	$1,236
Audit-related fees	210	285
Total	$2,070	$1,521

Audit fees are primarily for the audit of the Partnership's consolidated financial statements, including the audit of the effectiveness of the Partnership's internal control over financial reporting, consents, comfort letters, other audits, and the reviews of the Partnership's financial statements included in the Forms 10-Q. Audit-related fees are primarily for certain financial accounting consultations.

Audit Committee Approval of Audit and Non-Audit Services

The Audit Committee of the Partnership's general partner has adopted a Pre-Approval Policy with respect to services that may be performed by KPMG LLP. This policy lists specific audit-related services as well as any other services that KPMG LLP is authorized to perform and sets out specific dollar limits for each specific service, which may not be exceeded without additional Audit Committee authorization. The Audit Committee receives quarterly reports on the status of expenditures pursuant to that Pre-Approval Policy. The Audit Committee reviews the policy at least annually in order to approve services and limits for the current year. Any service that is not clearly enumerated in the policy must receive specific pre-approval by the Audit Committee or by its Chairman, to whom such authority has been conditionally delegated, prior to engagement. During 2018, no fees for services outside the scope of audit, review, or attestation that exceed the waiver provisions of 17 CFR 210.2-01(c)(7)(i)(C) were approved by the Audit Committee.
The Audit Committee has approved the appointment of KPMG LLP as independent registered public accounting firm to conduct the audit of the Partnership's consolidated financial statements for the year ended December 31, 2019.

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PART IV

Item 15. Exhibits, Financial Statement Schedules

(a)(1) Financial Statements

Our consolidated financial statements are included under Part II, Item 8 of this Form 10-K. For a listing of these statements and accompanying footnotes, see the Index to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

(a)(2) Financial Statement Schedules

Financial statement schedules have been omitted because they are not required, not applicable, or the information is included under Part II, Item 8 of this Form 10-K.

(a)(3) Exhibits

Exhibit Index

Exhibit Number	Description
2.1#	Contribution, Conveyance and Assumption Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, Anadarko Petroleum Corporation, WGR Holdings, LLC, Western Gas Resources, Inc., WGR Asset Holding Company LLC, Western Gas Operating, LLC and WGR Operating, LP, dated as of May 14, 2008 (incorporated by reference to Exhibit 10.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
2.2#	Contribution Agreement, dated as of November 11, 2008, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on November 13, 2008, File No. 001-34046).
2.3#	Contribution Agreement, dated as of July 10, 2009, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, Anadarko Uintah Midstream, LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on July 23, 2009, File No. 001-34046).
2.4#	Contribution Agreement, dated as of January 29, 2010 by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, Mountain Gas Resources LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on February 3, 2010 File No. 001-34046).
2.5#	Contribution Agreement, dated as of July 30, 2010, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on August 5, 2010, File No. 001-34046).
2.6#	Purchase and Sale Agreement, dated as of January 14, 2011, by and among Western Gas Partners, LP, Kerr-McGee Gathering LLC and Encana Oil & Gas (USA) Inc. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on January 18, 2011 File No. 001-34046).
2.7#	Contribution Agreement, dated as of December 15, 2011, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western

	Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 15, 2011, File No. 001-34046).
2.8#	Contribution Agreement, dated as of February 27, 2013, by and among Anadarko Marcellus Midstream, L.L.C., Western Gas Partners, LP, Western Gas Operating, LLC, WGR Operating, LP, Anadarko Petroleum Corporation and Anadarko E&P Onshore LLC (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 5, 2013, File No. 001-34046).

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Exhibit Number	Description
2.9#	Contribution Agreement, dated as of February 27, 2014, by and among WGR Asset Holding Company LLC, APC Midstream Holdings, LLC, Western Gas Partners, LP, Western Gas Operating, LLC, WGR Operating, LP and Anadarko Petroleum Corporation (incorporated by reference to Exhibit 2.9 to Western Gas Partners, LP's Annual Report on Form 10-K filed on February 28, 2014, File No. 001-34046).
2.10#	Agreement and Plan of Merger, dated October 28, 2014, by and among Western Gas Partners, LP, Maguire Midstream LLC and Nuevo Midstream, LLC (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on October 28, 2014, File No. 001-34046).
2.11#	Purchase and Sale Agreement, dated as of March 2, 2015, by and among WGR Asset Holding Company LLC, Delaware Basin Midstream, LLC, Western Gas Partners, LP, and Anadarko Petroleum Corporation (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 3, 2015, File No. 001-34046).
2.12#	Amendment No. 1 to Purchase and Sale Agreement, dated as of May 22, 2017, by and between WGR Asset Holding Company LLC and Delaware Basin Midstream, LLC (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 23, 2017, File No. 001-34046).
2.13#	Contribution Agreement, dated as of February 24, 2016, by and among WGR Asset Holding Company, LLC, APC Midstream Holdings, LLC, Western Gas Partners, LP, Western Gas Operating, LLC, WGR Operating, LP and Anadarko Petroleum Corporation (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 1, 2016, File No. 001-34046).
2.14#	Interest Swap and Purchase Agreement, dated February 9, 2017, among Western Gas Partners, LP, WGR Operating, LP, Delaware Basin JV Gathering, LLC, Williams Partners L.P., Williams Midstream Gas Services LLC and Appalachia Midstream Services, L.L.C. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on February 9, 2017, File No. 001-34046).
2.15#	Contribution Agreement and Agreement and Plan of Merger, dated as of November 7, 2018, by and among Anadarko Petroleum Corporation, Anadarko E&P Onshore LLC, APC Midstream Holdings, LLC, Western Gas Equity Partners, LP, Western Gas Equity Holdings, LLC, Western Gas Partners, LP, Western Gas Holdings, LLC, Clarity Merger Sub, LLC, WGR Asset Holding Company LLC, WGR Operating, LP, Kerr-McGee Gathering LLC, Kerr-McGee Worldwide Corporation and Delaware Basin Midstream, LLC, (incorporated by reference to Exhibit 2.1 to Western Gas Equity Partners, LP's Current Report on Form 8-K filed on November 8, 2018, File No. 001-35753).
3.1	Certificate of Limited Partnership of Western Gas Partners, LP (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Registration Statement on Form S-1 filed on October 15, 2007, File No. 333-146700).
3.2	Second Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated March 14, 2016 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 16, 2016, File No. 001-34046).
3.3	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated March 14, 2016 (incorporated by reference to Exhibit 3.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 16, 2016, File No. 001-34046).
3.4	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated February 22, 2017 (incorporated by reference to Exhibit 3.4 to Western Gas Partners, LP's Annual Report on Form 10-K filed on February 23, 2017, File No. 001-34046).
3.5	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated November 9, 2017 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on November 9, 2017, File No. 001-34046).
3.6	Certificate of Formation of Western Gas Holdings, LLC (incorporated by reference to Exhibit 3.3 to Western Gas Partners, LP's Registration Statement on Form S-1 filed on October 15, 2007, File No. 333-146700).
3.7	

	Second Amended and Restated Limited Liability Company Agreement of Western Gas Holdings, LLC, dated December 12, 2012 (incorporated by reference to Exhibit 3.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 12, 2012, File No. 001-34046).
4.1	Specimen Unit Certificate for the Common Units (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Quarterly Report on Form 10-Q filed on June 13, 2008, File No. 001-34046).
4.2	Indenture, dated as of May 18, 2011, among Western Gas Partners, LP, as Issuer, the Subsidiary Guarantors named therein, as Guarantors, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 18, 2011, File No. 001-34046).

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Exhibit Number	Description
4.3	First Supplemental Indenture, dated as of May 18, 2011, among Western Gas Partners, LP, as Issuer, the Subsidiary Guarantors named therein, as Guarantors, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 18, 2011, File No. 001-34046).
4.4	Form of 5.375% Senior Notes due 2021 (incorporated by reference to Exhibit 4.3, which is included as Exhibit A to Exhibit 4.2, to Western Gas Partners, LP's Current Report on Form 8-K filed on May 18, 2011, File No. 001-34046).
4.5	Fourth Supplemental Indenture, dated as of June 28, 2012, among Western Gas Partners, LP, as Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on June 28, 2012, File No. 001-34046).
4.6	Form of 4.000% Senior Notes due 2022 (incorporated by reference to Exhibit 4.2, which is included as Exhibit A to Exhibit 4.1, to Western Gas Partners, LP's Current Report on Form 8-K filed on June 28, 2012, File No. 001-34046).
4.7	Fifth Supplemental Indenture, dated as of August 14, 2013, among Western Gas Partners, LP, as Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on August 14, 2013, File No. 001-34046).
4.8	Form of 2.600% Senior Notes due 2018 (incorporated by reference to Exhibit 4.2, which is included as Exhibit A to Exhibit 4.1, to Western Gas Partners, LP's Current Report on Form 8-K filed on August 14, 2013, File No. 001-34046).
4.9	Sixth Supplemental Indenture, dated as of March 20, 2014, among Western Gas Partners, LP, as Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 20, 2014, File No. 001-34046).
4.10	Form of 5.450% Senior Notes due 2044 (incorporated by reference to Exhibit 4.4, which is included as Exhibit A to Exhibit 4.2, to Western Gas Partners, LP's Current Report on Form 8-K filed on March 20, 2014, File No. 001-34046).
4.11	Seventh Supplemental Indenture, dated as of June 4, 2015, among Western Gas Partners, LP, as Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on June 4, 2015, File No. 001-34046).
4.12	Form of 3.950% Senior Notes due 2025 (incorporated by reference to Exhibit 4.2, which is included as Exhibit A to Exhibit 4.1, to Western Gas Partners, LP's Current Report on Form 8-K filed on June 4, 2015, File No. 001-34046).
4.13	Eighth Supplemental Indenture, dated as of July 12, 2016, among Western Gas Partners, LP, as Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on July 12, 2016, File No. 001-34046).
4.14	Form of 4.650% Senior Notes due 2026 (incorporated by reference to Exhibit 4.2, which is included as Exhibit A to Exhibit 4.1, to Western Gas Partners, LP's Current Report on Form 8-K filed on July 12, 2016, File No. 001-34046).
4.15	Ninth Supplemental Indenture, dated as of March 2, 2018, among Western Gas Partners, LP, as Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 2, 2018, File No. 001-34046).
4.16	Form of 4.500% Senior Notes due 2028 (incorporated by reference to Exhibit 4.2, which is included as Exhibit A-1 to Exhibit 4.1, to Western Gas Partners, LP's Current Report on Form 8-K filed on March 2, 2018, File No. 001-34046).
4.17	Form of 5.300% Senior Notes due 2048 (incorporated by reference to Exhibit 4.3, which is included as Exhibit A-2 to Exhibit 4.1, to Western Gas Partners, LP's Current Report on Form 8-K filed on March 2, 2018, File No. 001-34046).
4.18	

	Tenth Supplemental Indenture, dated as of August 9, 2018, by and between Western Gas Partners, LP, as Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on August 9, 2018, File No. 001-34046).
4.19	Form of 4.750% Senior Notes due 2028 (incorporated by reference to Exhibit 4.2, which is included as Exhibit A-1 to Exhibit 4.1, to Western Gas Partners, LP's Current Report on Form 8-K file on August 9, 2018, File No. 001-34046).
4.20	Form of 5.500% Senior Notes due 2048 (incorporated by reference to Exhibit 4.3, which is included as Exhibit A-2 to Exhibit 4.1, to Western Gas Partners, LP's Current Report on Form 8-K file on August 9, 2018, File No. 001-34046).

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Exhibit Number	Description
4.21	Registration Rights Agreement by and between Western Gas Partners, LP and the Purchasers party thereto, dated as of March 14, 2016, (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 16, 2016, File No. 001-34046).
4.22	Consent and Conversion Agreement, dated as of February 22, 2017, by and among Western Gas Partners, LP and the holders of the outstanding Series A Preferred Units party thereto (incorporated by reference to Exhibit 4.16 to Western Gas Partners, LP's Annual Report on Form 10-K filed on February 23, 2017, File No. 001-34046).
10.1	Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC and Anadarko Petroleum Corporation, dated as of May 14, 2008 (incorporated by reference to Exhibit 10.3 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.2	Amendment No. 1 to Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, and Anadarko Petroleum Corporation, dated as of December 19, 2008 (incorporated by reference to Exhibit 10.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).
10.3	Amendment No. 2 to Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, and Anadarko Petroleum Corporation, dated as of July 22, 2009 (incorporated by reference to Exhibit 10.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on July 23, 2009, File No. 001-34046).
10.4	Amendment No. 3 to Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, and Anadarko Petroleum Corporation, dated as of December 31, 2009 (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on January 7, 2010, File No. 001-34046).
10.5	Amendment No. 4 to Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, and Anadarko Petroleum Corporation, dated as of January 29, 2010 (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on February 3, 2010, File No. 001-34046).
10.6	Amendment No. 5 to Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, and Anadarko Petroleum Corporation, dated as of August 2, 2010 (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on August 5, 2010, File No. 001-34046).
10.7	Services And Secondment Agreement between Western Gas Holdings, LLC and Anadarko Petroleum Corporation dated May 14, 2008 (incorporated by reference to Exhibit 10.4 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.8	Amendment No. 1 to Services And Secondment Agreement between Western Gas Holdings, LLC and Anadarko Petroleum Corporation dated December 10, 2015 (incorporated by reference to Exhibit 10.8 to Western Gas Partners, LP's Annual Report on Form 10-K filed on February 25, 2016, File No. 001-34046).
10.9	Tax Sharing Agreement by and among Anadarko Petroleum Corporation and Western Gas Partners, LP, dated as of May 14, 2008 (incorporated by reference to Exhibit 10.5 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.10	Anadarko Petroleum Corporation Fixed Rate Note due 2038 (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.11	Form of Commodity Price Swap Agreement (incorporated by reference to Exhibit 10.3 to Western Gas Partners, LP's Quarterly Report on Form 10-Q filed on May 6, 2010, File No. 001-34046).
10.12‡	Form of Indemnification Agreement by and between Western Gas Holdings, LLC, its Officers and Directors (incorporated by reference to Exhibit 10.10 to Amendment No. 2 to Western Gas Partners, LP's Registration Statement on Form S-1 filed on January 23, 2008, File No. 333-146700).
10.13‡	Western Gas Partners, LP 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.13 to Western Gas Partners, LP's Quarterly Report on Form 10-Q filed on June 13, 2008, File No. 001-34046).

10.14‡	Form of Award Agreement under the Western Gas Partners, LP 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.9 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.15‡	Western Gas Partners, LP 2017 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on October 17, 2017, File No. 001-34046).
10.16‡	Form of Award Agreement under the Western Gas Partners, LP 2017 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.8 to Western Gas Partners, LP's Post-Effective Amendment No. 1 to Registration Statement on Form S-8 filed on December 13, 2017, File No. 333-151317).

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Exhibit Number	Description
10.17†	Amended and Restated Limited Liability Company Agreement of Chipeta Processing LLC effective July 23, 2009 (incorporated by reference to Exhibit 10.4 to Western Gas Partners, LP's Quarterly Report on Form 10-Q filed on November 12, 2009, File No. 001-34046).
10.18	Second Amended and Restated Revolving Credit Agreement, dated as of February 26, 2014, among Western Gas Partners, LP, Wells Fargo Bank National Association, as the administrative agent and the lenders party thereto (incorporated by reference to Exhibit 10.15 to Western Gas Partners, LP's Annual Report on Form 10-K filed on February 28, 2014, File No. 001-34046).
10.19	First Amendment to Second Amended and Restated Revolving Credit Agreement, dated as of October 20, 2015, among Western Gas Partners, LP, Wells Fargo Bank, National Association, as administrative agent and the lenders party thereto (incorporated by reference to Exhibit 10.17 to Western Gas Partners, LP's Annual Report on Form 10-K filed on February 23, 2017, File No. 001-34046).
10.20	Second Amendment to Second Amended and Restated Revolving Credit Agreement, dated as of December 16, 2016, among Western Gas Partners, LP, Wells Fargo Bank, National Association, as administrative agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 16, 2016, File No. 001-34046).
10.21	Third Amended and Restated Revolving Credit Agreement, dated as of February 15, 2018, among Western Gas Partners, LP, Wells Fargo Bank National Association, as the administrative agent and the lenders party thereto (incorporated by reference to Exhibit 10.21 to Western Gas Partners, LP's Annual Report on Form 10-K filed on February 16, 2018, File No. 001-34046).
10.22	First Amendment to Third Amended and Restated Revolving Credit Agreement, dated as of December 19, 2018, among Western Gas Partners, LP, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 20, 2018, File No. 001-34046).
10.23	364-Day Credit Agreement, dated as of December 19, 2018, among Western Gas Partners, LP, Barclays Bank PLC, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 20, 2018, File No. 001-34046).
10.24	Fourth Amended and Restated Indemnification Agreement, dated March 14, 2016, between Western Gas Holdings, LLC and Western Gas Resources, Inc (incorporated by reference to Exhibit 10.19 to Western Gas Partners, LP's Annual Report on Form 10-K filed on February 23, 2017, File No. 001-34046).
10.25	First Amendment to Fourth Amended and Restated Indemnification Agreement, dated February 15, 2018, between Western Gas Holdings, LLC and Western Gas Resources, Inc (incorporated by reference to Exhibit 10.23 to Western Gas Partners, LP's Annual Report on Form 10-K filed on February 16, 2018, File No. 001-34046).
10.26	AMH Indemnification Agreement, dated March 3, 2014, between Western Gas Holdings, LLC and APC Midstream Holdings, LLC (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 5, 2014, File No. 001-34046).
10.27	KWC Indemnification Agreement, dated March 14, 2016, between Western Gas Holdings, LLC and Kerr-McGee Worldwide Corporation (incorporated by reference to Exhibit 10.21 to Western Gas Partners, LP's Annual Report on Form 10-K filed on February 23, 2017, File No. 001-34046).
10.28	Unit Purchase Agreement, dated October 28, 2014, by and among Western Gas Partners, LP, APC Midstream Holdings, LLC and Anadarko Petroleum Corporation (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on October 28, 2014, File No. 001-34046).
10.29†	Gas Gathering Agreement effective July 1, 2010 between Kerr-McGee Gathering LLC and Kerr-McGee Oil & Gas Onshore LP, as amended by Amendment No. 1 dated August 4, 2011, Amendment No. 2 dated December 3, 2012, Amendment No. 3 dated November 19, 2013 and Amendment No. 4 dated June 2, 2014 (incorporated by reference to Exhibit 10.23 to Western Gas Partners, LP's Annual Report on Form 10-K filed

	on February 26, 2015, File No. 001-34046).
10.30†	Amendment to Gas Gathering Agreement effective August 1, 2017, between Kerr-McGee Gathering LLC and Kerr-McGee Oil and Gas Onshore LP (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Quarterly Report on Form 10-Q filed on July 26, 2017, File No. 001-34046).
10.31†	Amendment to Gas Gathering Agreement effective January 1, 2018, between Kerr-McGee Gathering LLC and Kerr-McGee Oil and Gas Onshore LP (incorporated by reference to Exhibit 10.29 to Western Gas Partners, LP's Annual Report on Form 10-K filed on February 16, 2018, File No. 001-34046).
10.32	Board Observation Agreement, dated March 14, 2016, among Western Gas Partners, LP, Western Gas Holdings, LLC, Western Gas Equity Partners, LP and the persons set forth on Schedule A thereto (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 16, 2016, File No. 001-34046).

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Exhibit Number	Description
10.33†	Amendment to Gas Gathering Agreement, dated May 10, 2018, between Kerr-McGee Gathering LLC and Kerr-McGee Oil & Gas Onshore LP (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Quarterly Report on Form 10-Q filed on August 1, 2018, File No. 001-34046).
10.34†	Gas Gathering Agreement between Anadarko E&P Onshore LLC and Delaware Basin Midstream, LLC, dated October 8, 2018 (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Quarterly Report on Form 10-Q filed on October 31, 2018, File No. 001-34046).
21.1*	List of Subsidiaries of Western Gas Partners, LP.
23.1*	Consent of KPMG LLP.
31.1*	Certification of Chief Executive Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

* Filed herewith

** Furnished herewith

\# Pursuant to Item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted schedule to the Securities and Exchange Commission upon request.

† Portions of this exhibit, which was previously filed with the Securities and Exchange Commission, were omitted pursuant to a request for confidential treatment. The omitted portions were filed separately with the Securities and Exchange Commission.

‡ Management contracts or compensatory plans or arrangements required to be filed pursuant to Item 15.

Item 16. Form 10-K Summary

Not applicable.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

WESTERN GAS PARTNERS, LP

February 20, 2019

/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)

Each person whose signature appears below constitutes and appoints Robin H. Fielder and Jaime R. Casas, and each of them, either one of whom may act without joinder of the other, his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any or all amendments to this Form 10-K, and to file the same, with all, exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each, and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, and each of them, or the substitute or substitutes of any or all of them, may lawfully do or cause to be done by virtue hereof.

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Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 20, 2019.

Signature	Title (Position with Western Gas Holdings, LLC)
/s/ Benjamin M. Fink Benjamin M. Fink	Chairman and Director
/s/ Robin H. Fielder Robin H. Fielder	President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ Jaime R. Casas Jaime R. Casas	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)
/s/ Robert G. Gwin Robert G. Gwin	Director
/s/ Daniel E. Brown Daniel E. Brown	Director
/s/ Mitchell W. Ingram Mitchell W. Ingram	Director
/s/ Steven D. Arnold Steven D. Arnold	Director
/s/ Milton Carroll Milton Carroll	Director
/s/ James R. Crane James R. Crane	Director
/s/ David J. Tudor David J. Tudor	Director