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.

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.

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.

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.

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