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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2019

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: 001-38212

Oasis Midstream Partners LP

(Exact name of registrant as specified in its charter)

Delaware	**47-1208855**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1001 Fannin Street, Suite 1500 Houston, Texas	**77002**
(Address of principal executive offices)	(Zip Code)

(281) 404-9500
(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Units Representing Limited Partner Interests	OMP	The NASDAQ Stock Market LLC

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 ☐ 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 ☒

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 ☒ 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 ☒ No ☐

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	☐	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 ☒

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant’s most recently completed second fiscal quarter: $232,535,400.

At February 19, 2020, there were 33,811,366 units representing limited partner interests (consisting of 20,061,366 common units and 13,750,000 subordinated units) outstanding.

Documents Incorporated by Reference

None

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. Forward-looking statements give our current expectations, contain projections of results of operations or of financial condition or provide forecasts of future events. Words such as “may,” “assume,” “forecast,” “position,” “predict,” “strategy,” “expect,” “intend,” “plan,” “estimate,” “anticipate,” “believe,” “project,” “budget,” “potential,” “continue” and other similar expressions are used to identify forward-looking statements.

Forward-looking statements can be affected by the assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed. When considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements discussed below and detailed under Part I, Item 1A. “Risk Factors” in this Annual Report on Form 10-K. Actual results may vary materially. Although forward-looking statements reflect our good faith beliefs at the time they are made, you are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and you should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include but are not limited to:

- an inability of Oasis Petroleum (as defined below) or our other future customers to meet their operational and development plans on a timely basis or at all;
- the execution of our business strategies;
- the demand for and price of crude oil and natural gas, on an absolute basis and in comparison to the price of alternative and competing fuels;
- the fees we charge, and the margins we realize, from our midstream services;
- the cost of achieving organic growth in current and new markets;
- our ability to make acquisitions of other midstream infrastructure assets or other assets that complement or diversify our operations;
- our ability to make acquisitions of other assets on economically acceptable terms from Oasis Petroleum;
- the lack of asset and geographic diversification;
- the suspension, reduction or termination of our commercial agreements with Oasis Petroleum;
- labor relations and government regulations;
- competition and actions taken by third-party producers, operators, processors and transporters;
- outcomes of litigation and regulatory investigations, proceedings or inquiries;
- the demand for, and the costs of developing and conducting, our midstream infrastructure services;
- general economic conditions, including the risk of a prolonged economic slowdown or decline, or the risk of delay in a recovery, which can affect the long-term demand for natural gas and crude oil and related services;
- the price and availability of equity and debt financing;
- operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- potential effects arising from cyber threats, terrorist attacks and any consequential or other hostilities;
- interruption of our operations due to social, civil or political events or unrest;
- changes in environmental, safety and other laws and regulations;
- the effects of accounting pronouncements issued periodically during the periods covered by forward-looking statements;
- changes in our tax status;
- uncertainty regarding our future operating results; and
- certain factors discussed elsewhere in this Form 10-K.

All forward-looking statements speak only as of the date of this Annual Report on Form 10-K. We disclaim any obligation to update or revise these statements unless required by securities law. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Annual Report on Form 10-K are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. Some of the key factors which could cause actual results to vary from our expectations include, but are not limited to, commodity price volatility, inflation, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in projecting future throughput volumes, cash flow and access to capital, the timing of development expenditures and the other risks described under Part I, Item 1A. “Risk Factors” in this Annual Report on Form 10-K.

PART I

Item 1. Business

Overview

Oasis Midstream Partners LP (the "Partnership," "OMP," "we," "us," or "our") is a growth-oriented, fee-based master limited partnership formed by its sponsor, Oasis Petroleum Inc. (Nasdaq: OAS) ("Oasis Petroleum"), to own, develop, operate and acquire a diversified portfolio of midstream assets in North America that are integral to the crude oil and natural gas operations of Oasis Petroleum and are strategically positioned to capture volumes from other producers. Our midstream operations are performed within the Williston Basin and the Delaware Basin. We expect to grow acquisitively through accretive, dropdown acquisitions, as well as organically as Oasis Petroleum continues to develop its acreage. Additionally, we expect to grow by continuing to offer our services to third parties and through acquisitions of midstream assets from third parties. Through our entry into an Omnibus Agreement (as defined below), Oasis Petroleum has also granted us a right of first offer ("ROFO"), which converts into a right of first refusal ("ROFR") from any successor upon a change of control of Oasis Petroleum with respect to its retained interests in two of our development companies and any other midstream assets that Oasis Petroleum or any successor to Oasis Petroleum builds with respect to its acreage at the time of our initial public offering and elects to sell in the future (the "Subject Assets"). See "Contractual arrangements with Oasis Petroleum" below.

In the Williston Basin, we divide our operations into two primary areas with developed midstream infrastructure, both of which are supported by significant acreage dedications from Oasis Petroleum. In Wild Basin, we have acreage dedications from Oasis Petroleum in which we have the right to provide crude oil, natural gas and water services to support Oasis Petroleum's existing and future volumes. Outside of Wild Basin, we have acreage dedications from Oasis Petroleum for produced and flowback water services and freshwater services. We expanded our operations to the Delaware Basin in the fourth quarter of 2019 when, effective November 1, 2019, Oasis Petroleum agreed to assign to us certain crude oil gathering and produced and flowback water gathering and disposal assets under development to support Oasis Petroleum's production in the Delaware Basin (the "2019 Delaware Acquisition"). On November 1, 2019, we also entered into long-term commercial agreements with Oasis Petroleum, pursuant to which Oasis Petroleum dedicated acreage to us in the Delaware Basin for crude oil gathering and produced and flowback water gathering and disposal services. We have also received certain commitments and acreage dedications from third parties in the Williston Basin and the Delaware Basin, in which we have the right to provide our full suite of midstream services to support existing and future third party volumes.

We generate substantially all of our revenues through long-term, fee-based contractual arrangements with wholly-owned subsidiaries of Oasis Petroleum, as described below, which minimize our direct exposure to commodity prices. Furthermore, we do not take ownership of the crude oil or natural gas that we handle for Oasis Petroleum; however, we take ownership of natural gas under certain purchase arrangements with third parties. We believe our contractual arrangements provide us with stable and predictable cash flows over the long-term. We have entered into 15-year, fixed-fee contracts for natural gas services (gathering, compression, processing and gas lift), crude oil services (gathering, stabilization, blending and storage), produced and flowback water services (gathering and disposal) and freshwater services (fracwater and flushwater distribution) with Oasis Petroleum and certain of its wholly-owned subsidiaries. In the Williston Basin, we are also a party to the long-term, Federal Energy Regulatory Commission ("FERC") regulated transportation services agreement governing the transportation of crude oil via pipeline from the Wild Basin area to Johnson's Corner. In addition, we have increased customer diversification by entering into numerous agreements and transactions with third parties to provide our full suite of midstream services in the Williston Basin and the Delaware Basin.

Contributed Businesses and Organizational Structure

Our assets

We operate our midstream infrastructure business through our development companies ("DevCos"), two of which are jointly-owned with Oasis Petroleum.

Contributed businesses. On September 25, 2017, we completed our initial public offering. In connection with the initial public offering, Oasis Petroleum contributed to us a 100% ownership interest in Bighorn DevCo LLC ("Bighorn DevCo"), a 10% ownership interest in Bobcat DevCo LLC ("Bobcat DevCo") and a 40% ownership interest in Beartooth DevCo LLC ("Beartooth DevCo").

2018 Dropdown Acquisition. On November 19, 2018, we acquired an additional 15% ownership interest in Bobcat DevCo and an additional 30% ownership interest in Beartooth DevCo. See Note 4 to our consolidated financial statements.

2019 Capital Expenditures Arrangement. On February 22, 2019, we entered into the 2019 Capital Expenditures Arrangement (defined below) pursuant to which we agreed to pay up to $80 million of expansion capital expenditures associated with Oasis

Petroleum’s retained interest in Bobcat DevCo, in exchange for increasing ownership interest in Bobcat DevCo. During the year ended December 31, 2019, we made capital contributions to Bobcat DevCo pursuant to the 2019 Capital Expenditures Arrangement of $73.0 million. As a result, our ownership interest in Bobcat DevCo increased from 25% as of December 31, 2018 to 35.3% as of December 31, 2019. The 2019 Capital Expenditures Arrangement ended on December 31, 2019. See Note 5 to our consolidated financial statements.

2019 Delaware Acquisition. We expanded our operations to the Delaware Basin in 2019 when, effective November 1, 2019, Oasis Petroleum assigned to Panther DevCo LLC (“Panther DevCo”), an indirect wholly-owned subsidiary of the Partnership, certain crude oil gathering and produced and flowback water gathering and disposal assets located in the Delaware Basin.

The following table provides a summary of our DevCos, along with our ownership of these assets, as of December 31, 2019.

DevCos	Areas Served	Service Lines	OMP Ownership
Bighorn DevCo	Wild Basin	– Natural gas processing – Crude oil stabilization – Crude oil blending – Crude oil and NGL storage – Crude oil transportation	100%
Bobcat DevCo	Wild Basin	– Natural gas gathering – Natural gas compression – Gas lift – Crude oil gathering – Produced and flowback water gathering – Produced and flowback water disposal	35.3%
Beartooth DevCo	Alger Cottonwood Hebron Indian Hills Red Bank Wild Basin	– Produced and flowback water gathering – Produced and flowback water disposal – Freshwater supply and distribution	70%
Panther DevCo	Delaware Basin	– Crude oil gathering – Produced and flowback water gathering – Produced and flowback water disposal	100%

Bighorn DevCo. As of December 31, 2019, we own a 100% interest in Bighorn DevCo, which has substantial midstream assets to support development in the Wild Basin area, including:

- two natural gas processing plants with total processing capacity of 280 million standard cubic feet per day (“MMscfpd”) with enhanced propane recovery refrigeration units;
- four mechanical refrigeration units with total capacity of 40 MMscfpd to process natural gas volumes in excess of current capacity;
- an approximately 20-mile, 10-inch, FERC-regulated, mainline crude oil pipeline to the sales destination, Johnson’s Corner, with up to 75,000 barrels of crude oil per day (“Bopd”) of operating capacity; and
- a crude oil blending, stabilization and storage facility with 240,000 barrels of storage capacity.

Bobcat DevCo. As of December 31, 2019, we own a 35.3% interest in Bobcat DevCo, which has a significant midstream gathering system in the Wild Basin area, including:

- approximately 60 miles of six- and eight-inch crude oil gathering pipelines with initial capacity of approximately 50,000 Bopd, which can be expanded to approximately 70,000 Bopd;
- approximately 80 miles of eight-inch through 20-inch natural gas gathering pipelines with gathering capacity of up to approximately 250 MMscfpd and field compression capabilities;
- a natural gas lift system providing artificial lift throughout the field; and
- a produced and flowback water gathering and disposal system, consisting of six current disposal wells and approximately 60 miles of eight- and ten-inch pipeline with capacity of approximately 70,000 Bowpd.

Beartooth DevCo. As of December 31, 2019, we own a 70% interest in Beartooth DevCo, which has an extensive produced and flowback water gathering and freshwater distribution system in the Alger, Cottonwood, Hebron, Indian Hills, Red Bank and Wild Basin operating areas, including:

- nine strategically located produced and flowback water gathering pipeline systems spanning approximately 340 miles that connect approximately 980 crude oil and natural gas producing wells to our disposal well sites;
- 22 strategically located disposal wells that dispose of produced and flowback water from our produced and flowback water gathering pipeline systems or from third-party trucks;
- approximately 300 miles of freshwater pipeline that connect to approximately 445 crude oil and natural gas producing wells that are widely dispersed throughout our areas of operation, allowing for expansion to new wells in these areas for completion with minimal expansion capital expenditures;
- a freshwater distribution system, which includes four freshwater ponds, in McKenzie County, North Dakota, spanning approximately 90 miles; and
- a centralized freshwater intake facility from the Missouri River in McKenzie County, North Dakota.

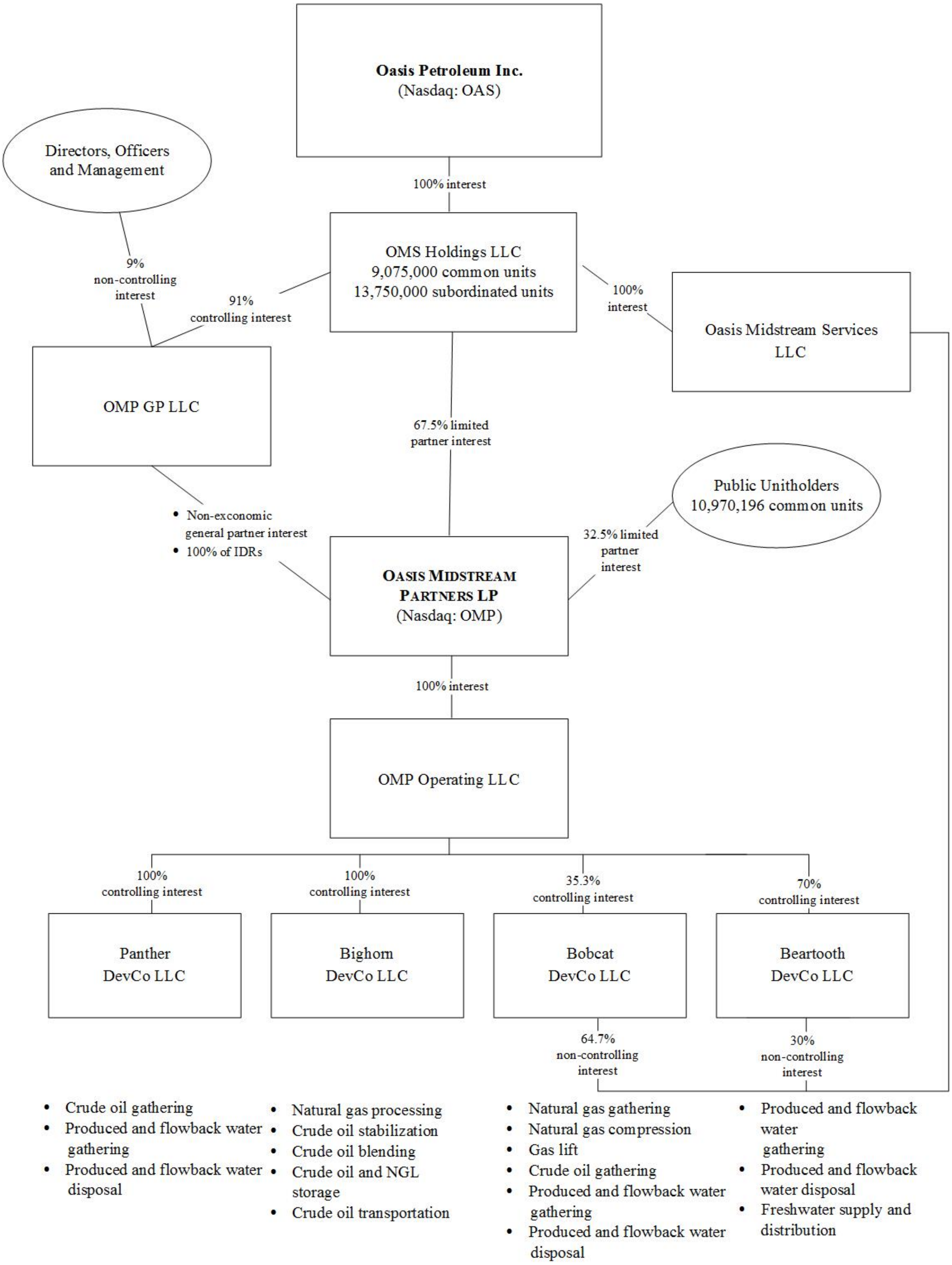
Panther DevCo. As of December 31, 2019, we own a 100% interest in Panther DevCo, which owns crude oil gathering and produced and flowback water gathering and disposal assets in the Delaware Basin, including:

- approximately 20 miles of four-inch through 12-inch crude oil gathering pipelines with an initial gathering capacity of approximately 20,000 Bopd, which is expected to increase to approximately 50,000 Bopd once fully constructed. Panther DevCo was servicing crude oil volumes from Oasis Petroleum and third party producers as of December 31, 2019; and
- a produced and flowback water gathering and disposal system, consisting of three current disposal wells and approximately 30 miles of four-inch through 24-inch pipeline with capacity of approximately 35,000 Bowpd.

Oasis Petroleum has acreage dedications to third parties for crude oil and natural gas services in the Williston Basin and the Delaware Basin. On dedicated acreage, if the third party dedication for crude oil and natural gas midstream services lapses on currently dedicated acreage, Oasis Petroleum will have the right to dedicate that acreage to us for such services or to develop crude oil and natural gas midstream assets that would be subject to our ROFO or ROFR, as applicable, in the event Oasis Petroleum elects to sell them.

Organizational structure

The following is a simplified diagram of our ownership structure as of December 31, 2019.



Our business strategy

The primary components of our business strategy are:

Focus on Providing Services Under Long-Term, Fixed-Fee Contracts to Mitigate Direct Commodity Price Exposure and Enhance the Stability of Our Cash Flows. We are party to long-term contracts with Oasis Petroleum for natural gas services (gathering, compression, processing and gas lift), crude oil services (gathering, stabilization, blending and storage), produced and flowback water services (gathering and disposal) and freshwater services (fracwater and flushwater distribution). We are also a party to the long-term FERC-regulated transportation services agreement governing the transportation of crude oil via pipeline from the Wild Basin area to Johnson's Corner. We generate substantially all of our revenues through these contracts. We have minimal direct exposure to commodity prices, and we do not take ownership of the crude oil or natural gas that we gather, compress, process, terminal, store or transport for Oasis Petroleum. Due to this and the fee-based, long-term nature of our contracts, we believe these agreements will provide us with stable and predictable cash flows. Additionally, we entered into multiple contracts to capture third party volumes during 2019, and we intend to continue to pursue long-term, fee-based contracts with third parties.

Leverage Our Relationship with Oasis Petroleum. We intend to leverage our relationship with Oasis Petroleum to expand our asset base and increase our cash flows through:

- *Organic Growth.* Our midstream infrastructure footprint services Oasis Petroleum's leading acreage position in the Williston Basin and the Delaware Basin. During 2019, Oasis Petroleum completed and placed on production 67 gross (41.6 net) operated wells in the Williston Basin and 11 gross (9.9 net) operated wells in the Delaware Basin. We anticipate we will be positioned to increase our throughput volumes and cash flows as Oasis Petroleum grows its production volumes through our crude oil, natural gas and water-related midstream assets. For the year ended December 31, 2019, our pipelines gathered approximately 93% of the produced and flowback water volumes produced from Oasis Petroleum's operated wells and disposed of approximately 89% of the produced and flowback water volumes produced from Oasis Petroleum's operated wells. We will seek to increase this percentage as we increase utilization on our existing pipelines and further develop our midstream infrastructure with volumes from Oasis Petroleum and third parties.

- *Dropdown Acquisitions from Oasis Petroleum.* As of December 31, 2019, Oasis Petroleum owns a 64.7% economic interest in Bobcat DevCo and a 30% economic interest in Beartooth DevCo, both of which are subject to our ROFO or ROFR, as applicable, with Oasis Petroleum or its successors. We anticipate that we will have the opportunity to make accretive acquisitions from Oasis Petroleum by acquiring the remaining equity interests in Bobcat DevCo and Beartooth DevCo. We also anticipate acquiring assets that are not currently included in the DevCos that we anticipate Oasis Petroleum will develop to support its production activities.

Attract Third-Party Customers. We have successfully added third party customers and expect to continue to attract incremental volumes from other upstream oil and gas operators to expand our systems and increase the utilization of our existing midstream assets. The scale of our assets and their strategic location near concentrated areas of current and expected future production make our geographic footprint difficult for competitors to replicate, thereby providing us the ability to gather incremental throughput volumes at a lower cost than new market entrants or competitors with less scale or undersized assets. We believe that our strategically located assets and our experience in designing, permitting, constructing and operating cost-efficient crude oil, natural gas and water-related midstream assets will allow us to continue to grow our third-party business.

Complete Accretive Acquisitions from Third Parties. In addition to growing our business organically and through dropdown acquisitions from Oasis Petroleum, we intend to make accretive acquisitions of midstream assets from third parties. Leveraging our knowledge of, and expertise in, the Williston Basin and the Delaware Basin, we intend to target and efficiently execute economically attractive acquisitions of midstream assets from third parties within and beyond our current areas of operation. We also intend to explore accretive acquisition opportunities from third parties outside of the Williston Basin and the Delaware Basin in support of any geographic expansion of Oasis Petroleum's operations.

Our competitive strengths

We believe that we will be able to successfully execute our business strategies because of the following competitive strengths:

Strategically Located Midstream Assets. Our midstream assets are strategically located in the Williston Basin and the Delaware Basin, and provide critical midstream infrastructure to our customers in a cost-efficient manner. We believe that the strategic location of our assets within the highly economic core of these basins, combined with our cost-advantaged midstream service offering, will enable us to continue to attract volumes from producers in these basins.

- *Demand for Midstream Infrastructure Services*. Our acreage dedications from Oasis Petroleum are located in the primary areas of focus for Oasis Petroleum’s drilling plans in the Williston Basin and the Delaware Basin. We believe the extensive midstream infrastructure we have built and are continuing to build provides a strategic footprint in the core of these basins and provides opportunities to continue to connect other third-party operators. We believe our midstream assets will continue to be able to compete for third-party business based on the cost-effective nature of our midstream services compared to the current alternatives for transportation of crude oil, natural gas and water in the Williston Basin and the Delaware Basin. Additionally, due to the core location of our assets, we believe that extensive development will occur in and around our assets in the current commodity price environment, and future development activity will be highly levered to any commodity price recovery.

- *Strategically Located Near Key Demand Centers*. We believe our crude oil pipeline to Johnson’s Corner provides a highly strategic takeaway alternative for operators in the core of the Williston Basin. Johnson’s Corner is a receipt point for the Dakota Access Pipeline, which has significantly improved in-basin pricing realizations for producers since coming online. In addition, our crude oil gathering system in the Delaware Basin is located in the oiliest, most economic area of the Delaware Basin, with the ability to move crude oil volumes to central hubs with connections to long haul crude oil pipelines that provide downstream access to premium coastal markets.

- *Full-Service Operational Flexibility*. In addition to our crude oil, natural gas and water gathering capabilities, our midstream assets in the Williston Basin also include crude oil blending, stabilization and storage, and a mainline FERC-regulated crude oil pipeline to the sales destination, Johnson’s Corner. Our natural gas processing complex, which includes two fully operational natural gas processing plants and four mechanical refrigeration units, has approximately 320 MMscfpd natural gas processing capacity. Our natural gas processing complex services natural gas production from both Oasis Petroleum and third parties. As production increases in the Williston Basin, our interconnected system is constructed to provide optionality, which increases our growth prospects and value proposition to additional third-party customers.

Stable and Predictable Cash Flows. We provide substantially all of our natural gas gathering, compression, processing and gas lift; crude oil gathering, stabilization, blending and storage; produced and flowback water gathering and disposal; and freshwater distribution services to Oasis Petroleum on a fixed-fee basis under long-term contracts. Our assets are newly constructed, leading to relatively low maintenance capital expenditure requirements, which also enhances the stability of our cash flows. We believe that the operating history of Oasis Petroleum and other companies in the Williston Basin and the Delaware Basin has reduced development risk and increased the predictability of future production of new wells. This operating history, combined with the structure of our commercial contracts, is expected to promote the generation of stable and predictable cash flows.

Our Strategic Affiliation with Oasis Petroleum. We believe that, as a result of owning a 91% controlling interest in OMP GP LLC (our “General Partner”), its ownership of 67.5% of our outstanding units and its retained interests in two of our DevCos, Oasis Petroleum is incentivized to promote and support our growth plan and to pursue projects that enhance the overall value of our business. We believe our assets are highly efficient, with demonstrated high rates of availability and operational reliability designed to withstand harsh conditions, and can be operated at what we consider to be relatively low costs. Additionally, our assets are strategically located within Oasis Petroleum’s acreage positions and are in close proximity to other operators in the Williston Basin and the Delaware Basin, positioning us as a leading provider of midstream services in these basins.

- *The Development of the Williston Basin and the Delaware Basin is a Strategic Priority for Oasis Petroleum.* Oasis Petroleum owns and operates a large inventory of leasehold acreage in the core areas of the Williston Basin and the Delaware Basin. As of December 31, 2019 approximately 97% and 71% of Oasis Petroleum's net acreage in the Williston Basin and the Delaware Basin, respectively, was held by production. We believe we will directly benefit from Oasis Petroleum’s continued development of its Williston Basin and Delaware Basin acreage, where it serves as operator with respect to substantially all of its net wells.

- *Dropdown Acquisition Opportunities.* As of December 31, 2019, Oasis Petroleum retains a 64.7% economic interest in Bobcat DevCo and a 30% economic interest in Beartooth DevCo, both of which are subject to our ROFO or ROFR, as applicable, with Oasis Petroleum or its successors. In addition, we believe Oasis Petroleum will continue to build crude oil, natural gas and water-related midstream assets to support its production growth. We anticipate that we will have the opportunity to make accretive acquisitions from Oasis Petroleum by acquiring the remaining equity interests in Bobcat DevCo and Beartooth DevCo. In addition, we anticipate acquiring midstream assets that Oasis Petroleum elects to develop and sell to support its production activities in the Williston Basin and the Delaware Basin.

Financial Flexibility and Strong Capital Structure. We have a balanced capital structure which, when combined with our stable and predictable cash flows, should allow us to access capital markets when they are constructive. We believe that our ownership structure, available borrowing capacity and potential ability to access the equity and debt capital markets will provide us with the financial flexibility to successfully execute our organic growth and acquisition strategies. We will seek to maintain a disciplined approach of executing and financing acquisitions and growth projects with an appropriate mix of equity and debt based on market conditions.

Experienced Management and Operating Teams with Strong Execution Track Record. Through our relationship with Oasis Petroleum, we will benefit from a significant pool of management talent, strong relationships throughout the energy industry and broad operational, technical, business development and administrative infrastructure. These professionals have significant experience building, permitting and operating assets, including crude oil and natural gas gathering, natural gas processing, produced and flowback water gathering and disposal and freshwater distribution. We believe access to these personnel will, among other things, enhance the efficiency of our operations and accelerate our growth.

Our relationship with Oasis Petroleum

Our relationship with Oasis Petroleum is one of our principal strengths. As of December 31, 2019, Oasis Petroleum owns an aggregate 67.5% limited partner interest in us and a 91% controlling interest in our General Partner, which owns all of our IDRs and our non-economic general partner interest. As of December 31, 2019, Oasis Petroleum also indirectly owns 64.7% of Bobcat DevCo and 30% of Beartooth DevCo. Oasis Petroleum intends to use us as an integral vehicle to support its production in the Williston Basin and the Delaware Basin and the primary vehicle to grow the midstream infrastructure business that supports its production activities. Additionally, our assets are strategically located within Oasis Petroleum's acreage positions and are in close proximity to other operators, positioning us to become a leading provider of midstream services in the Williston Basin and the Delaware Basin.

We intend to expand our business through the acquisition of Oasis Petroleum's retained interests in Bobcat DevCo and Beartooth DevCo, the acquisition of midstream assets that Oasis Petroleum constructs, through its wholly-owned subsidiary Oasis Midstream Services LLC ("OMS"), in the Williston Basin, Delaware Basin or in any other crude oil or natural gas basins that Oasis Petroleum may pursue, through selective acquisitions of complementary assets from third parties and by organic growth from the increased usage of our services by Oasis Petroleum and other third parties as they continue to develop their crude oil and natural gas resources. Oasis Petroleum accounts for a substantial portion of our revenues. It is the only customer that accounts for more than 10% of our revenues and the loss of Oasis Petroleum as a customer would have a material adverse effect on us. See "Item 1A. Risk Factors."

Contractual arrangements with Oasis Petroleum

As of December 31, 2019, we are party to the following commercial agreements with certain wholly-owned subsidiaries of Oasis Petroleum:

Omnibus Agreement; Subject Assets

The Partnership entered into an omnibus agreement (the "Omnibus Agreement") with Oasis Petroleum and certain of its affiliates, pursuant to which:

- Oasis Petroleum granted the Partnership a ROFO with respect to (i) its retained interests in each of Bobcat DevCo and Beartooth DevCo and (ii) any other midstream assets that Oasis Petroleum or any successor to Oasis Petroleum builds with respect to its acreage at the time of our initial public offering and elects to sell in the future, which ROFO converts into a ROFR upon a change of control of Oasis Petroleum;
- Oasis Petroleum provided the Partnership with a license to use certain Oasis Petroleum-related names and trademarks in connection with the Partnership's operations; and
- Oasis Petroleum agreed to indemnify the Partnership for certain environmental and other liabilities, including certain liabilities related to the Mirada litigation (as described in the Omnibus Agreement, the "Mirada Litigation"), and the Partnership agreed to indemnify Oasis Petroleum for certain environmental and other liabilities related to the Partnership's assets to the extent Oasis Petroleum is not required to indemnify the Partnership. See "Item 3. Legal Proceedings" below.

The maximum liability of Oasis Petroleum for its indemnification obligations under the Omnibus Agreement will not exceed $15 million and Oasis Petroleum will not have any obligation under this indemnification until the Partnership’s aggregate losses exceed $100,000; provided that Oasis Petroleum’s indemnification obligations with respect to the Mirada Litigation are not subject to the aggregate limit or deductible. Oasis Petroleum will have no indemnification obligations with respect to environmental claims made as a result of additions to or modifications of environmental laws enacted or promulgated after the closing of the initial public offering and its indemnification obligations (other than with respect to the Mirada Litigation) will terminate on the third anniversary of the closing of the initial public offering.

The Partnership has agreed to indemnify Oasis Petroleum against all losses, including environmental liabilities, related to the operation of the Partnership’s assets after the closing of the initial public offering, to the extent Oasis Petroleum is not required to indemnify the Partnership for such losses.

The initial term of the Omnibus Agreement will be ten years from September 25, 2017 and will thereafter automatically extend from year-to-year unless terminated by the Partnership or the General Partner. Oasis Petroleum may terminate the Omnibus Agreement in the event that it ceases to be an affiliate of the Partnership and may also terminate the Omnibus Agreement if the Partnership fails to pay amounts due under the agreement in accordance with its terms. Additionally, both the ROFO and the ROFR in the Omnibus Agreement will terminate in the event Oasis Petroleum elects to sell the General Partner to a third party (other than in connection with a change of control of Oasis Petroleum). The Omnibus Agreement may only be assigned by a party with the other parties’ consent.

Gas Gathering, Compression, Processing and Gas Lift Agreement

The Partnership entered into a Gas Gathering, Compression, Processing and Gas Lift Agreement with Oasis Petroleum North America LLC (“OPNA”), Oasis Petroleum Marketing LLC (“OPM”) and OMS (the “Gas Gathering Agreement”) pursuant to which (i) OPNA and OPM agreed to deliver into the Partnership’s natural gas gathering system all of the natural gas produced that is owned or controlled by OPNA or OPM (subject to certain limited exceptions) from certain dedicated acreage in the Wild Basin area and (ii) OMS and the Partnership will perform certain gathering, compression, processing and gas lift services. The Gas Gathering Agreement provides for an initial term of 15 years. With respect to gas processing, the agreement provides that gas produced from the dedicated acreage, together with any third-party volumes, will be processed at the Partnership’s existing processing complex up to its working capacity.

Crude Oil Gathering, Stabilization, Blending and Storage Agreement - Williston Basin areas

The Partnership entered into a Crude Oil Gathering, Stabilization, Blending and Storage Agreement with OPNA, OPM and OMS (the “Crude Oil Gathering Agreement”) pursuant to which (i) OPNA and OPM agreed to deliver into the Partnership’s crude oil gathering system all of the crude oil produced that is owned or controlled by OPNA or OPM (subject to certain limited exceptions) from certain dedicated acreage in the Wild Basin area and (ii) OMS and the Partnership will perform certain gathering, stabilizing, blending and storing services for the crude oil delivered. The Crude Oil Gathering Agreement provides for an initial term of 15 years.

Crude Oil Gathering Agreement - Delaware Basin areas

Panther DevCo entered into a Crude Oil Gathering Agreement with Oasis Petroleum Permian LLC (“OPP”) and OPM (the "Panther Crude Oil Gathering Agreement") pursuant to which OPP and OPM agreed to deliver into Panther DevCo's crude oil gathering system all of the crude oil produced that is owned and controlled by OPP or OPM (subject to certain limited exceptions) from certain dedicated acreage in the Delaware Basin. The Panther Crude Oil Gathering Agreement also provides Oasis Petroleum with certain purchase rights and Panther DevCo with certain sale rights with respect to the Gathering System (as defined therein), in the event of a change of control of the Partnership or Panther DevCo, which rights will expire after two years.The Panther Crude Oil Gathering Agreement provides for an initial term of 15 years.

Produced and Flowback Water Gathering and Disposal Agreement - Bobcat DevCo areas

The Partnership entered into a Produced and Flowback Water Gathering and Disposal Agreement with OPNA and OMS (the “Wild Basin Produced Water Gathering Agreement”) pursuant to which OPNA dedicated certain acreage in the Wild Basin area to the Partnership for produced and flowback water gathering and disposal services. The Wild Basin Produced Water Gathering Agreement provides for an initial term of 15 years.

Produced and Flowback Water Gathering and Disposal Agreement - Beartooth DevCo areas

The Partnership entered into a Produced and Flowback Water Gathering and Disposal Agreement with OPNA and OMS (the “Beartooth Produced Water Gathering Agreement”) pursuant to which OPNA dedicated certain acreage in the Alger, Cottonwood, Hebron, Indian Hills and Red Bank operating areas to the Partnership for produced and flowback water gathering and disposal services. The Beartooth Produced Water Gathering Agreement provides for an initial term of 15 years.

Produced and Flowback Water Gathering and Disposal Agreement - Delaware Basin areas

Panther DevCo entered into a Produced and Flowback Water Gathering and Disposal Agreement with OPP (the "Panther Produced Water Gathering Agreement") pursuant to which OPP dedicated certain acreage in the Delaware Basin to Panther DevCo for produced and flowback water gathering and disposal services. The Panther Produced Water Gathering Agreement also provides Oasis Petroleum with certain purchase rights and Panther DevCo with certain sale rights with respect to the Disposal System (as defined therein), in the event of a change of control of the Partnership or Panther DevCo, which rights will expire after two years. The Panther Produced Water Gathering Agreement provides for an initial term of 15 years.

Freshwater Purchase and Sales Agreement

The Partnership entered into a Freshwater Purchase and Sales Agreement with OPNA and OMS (the “Freshwater Purchase Agreement”) pursuant to which OPNA will purchase freshwater from the Partnership from time to time for use in its operations in the Hebron, Indian Hills, Red Bank and Wild Basin operating areas, including but not limited to distributing freshwater for hydraulic fracturing and production optimization services. The Freshwater Purchase Agreement provides for an initial term of 15 years.

Crude Transportation Services Agreement

Bighorn DevCo entered into an amendment and assignment agreement with OPM and OMS (the “Amendment and Assignment Agreement”) pursuant to which Bighorn DevCo became a party to the long-term, fixed-fee agreement previously entered into by OPM and OMS providing for crude transportation services from the Wild Basin area to Johnson’s Corner through a FERC-regulated pipeline system that has up to 75,000 barrels per day of operating capacity and firm capacity for committed shippers. The Amendment and Assignment Agreement is renewable at OPM’s option (subject to certain limitations) and includes minimum volume commitments that are not material to the Partnership’s operating results.

Capital expenditures

In 2019, gross capital expenditures were $212.9 million. Capital expenditures attributable to the Partnership were $198.6 million, of which $189.3 million was spent on expansion capital expenditures, $8.3 million was spent on maintenance capital expenditures and $0.9 million was related to capitalized interest.

On February 22, 2019, we entered into the MOU with Oasis Petroleum regarding the funding of Bobcat DevCo’s capital expenditures for the 2019 calendar year, referred to as the “2019 Capital Expenditures Arrangement”. Pursuant to the Amended and Restated Limited Liability Company Agreement of Bobcat DevCo LLC, as amended (the “First A&R Bobcat LLCA”), the Partnership and Oasis Petroleum are each required to make pro-rata capital contributions to Bobcat DevCo in accordance with their respective percentage ownership interests in Bobcat DevCo. Pursuant to the MOU, the Partnership agreed to make up to $80.0 million of capital expenditures to Bobcat DevCo that Oasis Petroleum would otherwise be required to contribute under the First A&R Bobcat LLCA. In connection with execution of the MOU, the Partnership and Oasis Petroleum amended the First A&R Bobcat LLCA and entered into the Second Amended and Restated Limited Liability Company Agreement of Bobcat DevCo LLC (the “Second A&R Bobcat LLCA”). The Second A&R Bobcat LLCA includes provisions applicable to the disproportionate capital contributions that the Partnership will make to Bobcat DevCo in connection with the 2019 Capital Expenditures Arrangement. Pursuant to the Second A&R Bobcat LLCA, upon the occurrence of a disproportionate capital contribution, the percentage interests of the Partnership and Oasis Petroleum in Bobcat DevCo will be adjusted to take into account the amount of the disproportionate capital contribution. During the year ended December 31, 2019, the Partnership made capital contributions to Bobcat DevCo pursuant to the 2019 Capital Expenditures Arrangement of $73.0 million. As a result, the Partnership’s ownership interest in Bobcat DevCo increased from 25% as of December 31, 2018 to 35.3% as of December 31, 2019. The 2019 Capital Expenditures Arrangement ended on December 31, 2019 (see Note 5 to our consolidated financial statements).

Our 2020 capital expenditures program, excluding acquisitions, will accommodate a gross capital expenditure level of approximately $110 million to $120 million, with approximately $68 million to $75 million attributable to the Partnership. We expect to spend approximately 6% to 8% of EBITDA for maintenance capital expenditures, which is included in our total capital expenditure program.

See “Part II. Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources.”

Competition

As a result of our long-term, fixed fee commercial agreements with Oasis Petroleum, we do not compete for the portion of Oasis Petroleum's existing operations for which we currently provide midstream infrastructure services. For areas where acreage is not dedicated to us, the DevCos will compete with similar enterprises in providing additional midstream infrastructure services in those areas of operation. Some of these competitors may expand or construct midstream infrastructure systems that would create additional competition for the services provided by the DevCos to crude oil and natural gas producers. In addition, third parties that are significant producers of crude oil and natural gas in the DevCos' areas of operation may develop their own midstream infrastructure systems in lieu of employing the DevCos' services.

Title to Our Properties

Substantially all of our interests in the real property on which our assets are located derive from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations, and we believe that we have satisfactory interests in and to these lands. We have leased or acquired easements, rights-of-way, permits or licenses in these lands without any material challenge known to us relating to the title to the land upon which the assets will be located, and we believe that we have satisfactory interests in 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.

Seasonality

Demand for crude oil and natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain crude oil and natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. In respect of our completed midstream systems, we do not expect seasonal conditions to have a material impact on our throughput volumes. Severe or prolonged winters may, however, impact our ability to complete additional well connections or construction projects, which may impact the rate of our growth. In addition, severe weather may also impact or slow the ability of Oasis Petroleum to execute its drilling and development plan and increase operating expenses associated with repairs or anti-freezing operations.

Insurance

We carry a variety of insurance coverages for our operations. However, our insurance may not be sufficient to cover any particular loss or may not cover all losses, and losses not covered by insurance would increase our costs. Also, insurance rates are subject to fluctuation, so future insurance coverage could increase our costs. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable, which could result in less coverage, increases in costs or higher deductibles and retentions.

Water and natural resource-related solid waste disposal involves several hazards and operational risks, including environmental damage from leaks, spills or vehicle accidents. To address the hazards inherent to our produced and flowback water gathering and disposal business, our insurance coverage includes commercial general liability, employer's liability, commercial automobile liability, sudden and accidental pollution and other coverage. Coverage for environmental and pollution-related losses is subject to significant limitations and is commonly excluded on such policies.

Pipeline Safety Regulation

Certain of our pipelines are subject to regulation by the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA") under the Hazardous Liquid Pipeline Safety Act ("HLPSA") with respect to crude oil and the Natural Gas Pipeline Safety Act ("NGPSA") with respect to natural gas. The HLPSA and NGPSA govern the design, installation, testing, construction, operation, replacement and management of crude oil and natural gas pipeline facilities. These laws have resulted in the adoption of rules by PHMSA, that, among other things, require transportation pipeline operators to implement integrity management programs to comprehensively evaluate certain relatively higher risk areas, known as high consequence areas ("HCAs") and moderate consequence areas ("MCAs") along pipelines and take additional safety measures to protect people and property in these areas. The HCAs for natural gas pipelines are predicated on high-population areas (which, for natural gas transmission pipelines, may include Class 3 and Class 4 areas), whereas HCAs for crude oil pipelines are based on high-population areas, certain drinking water sources and unusually sensitive ecological areas. An MCA is attributable to natural gas pipelines and is based on high-population areas as well as certain principal, high-capacity roadways, but an MCA does not meet the relatively higher population totals of an HCA and therefore are located outside of HCA coverages. In addition, states have adopted regulations similar to existing PHMSA regulations for certain intrastate gas and hazardous liquid pipelines, which regulations may impose more stringent requirements than found under federal law. Historically, our pipeline safety 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 be material in the future or that such future compliance costs will not have a material adverse effect on our business and operating results. New pipeline safety laws or regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement 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.

Legislation 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 HLPSA and NGPSA were amended by the Pipeline, Safety, Regulatory Certainty, and Job Creation Act of 2011 (the "2011 Pipeline Safety Act"). The 2011 Pipeline Safety Act increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. In June 2016, the 2016 Pipeline Safety Act (the "2016 Pipeline Safety Act") was passed, extending PHMSA's statutory mandate through September 2019 and, among other things, requiring PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and developing new safety standards for natural gas storage facilities. The 2016 Pipeline Safety Act also empowers PHMSA to address unsafe conditions or practice constituting imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of hazardous liquid or gas pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued an interim rule in 2016 and a final rule on October 1, 2019 to implement the agency's expanded authority to address such conditions or practices that pose an imminent hazard to life, property or the environment. Because the 2016 Pipeline Safety Act reauthorized PHMSA's hazardous liquid and gas pipeline programs only through September 30, 2019, we anticipate that Congress will issue an updated pipeline safety law in 2020 that will reauthorize those programs through 2023.

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, on October 1, 2019, PHMSA published 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 and expanded use of leak detection systems, regardless of the pipeline's proximity to an HCA (for example, integrity assessments at least once every 10 years for onshore, piggable, hazardous liquid pipeline segments located outside of HCAs, and expanded use of leak detection systems outside of HCAs on all regulated hazardous liquid pipelines other than offshore gathering and regulated rural gathering pipelines). The final rule was initially issued by PHMSA under the Obama Administration in late 2016, but publication and effectiveness of the final rule was subsequently delayed following the election of President Trump and change in presidential administrations in January 2017. The October 1, 2019 final rule becomes effective on July 1, 2020 and, in addition to the stated integrity management requirements, requires all hazardous liquid pipelines in or affecting an HCA to be capable of accommodating in-line inspection tools within the next 20 years unless the basic construction of a pipeline cannot be modified to permit that accommodation. Also, this final rule extends annual accident and safety-related conditional reporting requirements to hazardous liquid gravity lines and certain gathering lines and also imposes inspection requirements on hazardous liquid pipelines in areas affected by extreme weather events and natural disasters, such as hurricanes, landslides, floods, earthquakes or other similar events that are likely to damage infrastructure.

In a second example, in 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain gas lines and gathering lines including, among other things, expanding certain of PHMSA's current regulatory safety programs for natural gas pipelines in newly defined MCAs; requiring natural gas pipelines installed before 1970 and thus excluded from certain pressure testing obligations to be tested to determine their maximum allowable operating pressures ("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 natural gas pipelines and also require consideration of seismicity in evaluating threats to pipelines. PHMSA has since decided to split its 2016 proposed rule, which has become known as the "Gas Mega Rule," into three separate rulemaking proceedings to facilitate completion. The first of these three rulemakings, relating to onshore gas transmission pipelines, was published as a final rule on October 1, 2019, becomes effective on July 1, 2020 and imposes numerous requirements on such pipelines, including maximum allowable operating pressure reconfirmation, the assessment of additional pipeline mileage outside of HCAs (including all MCAs and those Class 3 and Class 4 areas not found in HCAs) within 14 years of the publication date and at least once every 10 years thereafter, the reporting of exceedances of maximum allowable operating pressures, and the consideration of seismicity as a risk factor in integrity management. The remaining rulemakings comprising the Gas Mega Rule are expected to be issued in 2020. New legislation or any new 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 the absence of the PHMSA pursuing any legal requirements, state agencies, to the extent authorized, may pursue state standards, including standards for rural gathering lines.

Environmental and Occupational Health and Safety Matters

Our crude oil gathering and transportation, natural gas gathering and processing, and produced and flowback water gathering and disposal services and related operations are subject to stringent federal, tribal, state and local environmental laws and regulations relating to worker health and safety, the handling, discharge or disposal of materials and wastes, and the protection of natural resources and the environment. These laws and regulations may impose numerous obligations that are applicable to our crude oil and natural gas exploration and production ("E&P") customers' operations, including, among other things, the acquisition of permits for regulated activities; the incurrence of capital or operating expenditures to limit or prevent releases of materials from operations; a limitation on the amounts and types of substances that may be released into the environment in connection with operations; a restriction on the way wastes are handled or disposed; a limitation or prohibition on activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; the imposition of investigatory and remedial actions to prevent or mitigate pollution conditions caused by operations or attributable to former operations; the imposition of specific safety and health standards addressing worker protections; and the imposition of substantial liabilities for pollution resulting from operations. Numerous governmental agencies, including the U.S. Environmental Protection Agency ("EPA"), the U.S. Occupational Safety and Health Administration ("OSHA") and analogous state agencies, issue regulations to implement and enforce these laws, for which compliance is often costly and difficult. 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 restrictions, delays, or cancellations in the permitting, development or expansion of projects, loss of leases and the issuance of injunctions limiting some or all of our operations in a particular area.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any new laws or regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement that result in more stringent and costly midstream management activities, or waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our financial position and results of operations. 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 be material in the future or that such future compliance will not have a material adverse effect on our business and operating results. We may be unable to pass on such increased compliance costs to our customers. Additionally, accidental spills or other releases may occur in the course of our operations and we cannot be sure that we will not incur significant costs and liabilities as a result of such spills or releases, including any third-party claims for damage to property, natural resources or persons.

Moreover, our E&P customers are also subject to these same laws and regulations. Any changes in environmental laws could limit our customers' businesses or encourage our customers to handle and dispose of wastes in other ways, which, in either case, could reduce the demand for our gathering, transportation, processing and disposal services and adversely impact our business. While compliance with some environmental laws and regulations creates a need for assets such as our own, other environmental laws and regulations could reduce the demand for our services. For instance, some states have considered laws mandating the recycling of produced and flowback water generated by crude oil and natural gas development and production activities. If such laws are passed, our customers may divert some produced and flowback water to recycling operations that may have otherwise been disposed of at our facilities.

The following is a summary of the more significant existing environmental and occupational health and safety laws and regulations, as amended from time to time, to which our business operations and the operations of our customers are subject and for which compliance in the future may have a material adverse impact on our capital expenditures, results of operations, or financial position.

Hazardous Substances and Wastes

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, non-hazardous wastes, hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of non-hazardous and hazardous waste and may impose strict joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed.

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have caused or contributed to the release of a "hazardous substance" into the environment. These classes of persons include the current and past owners or operators of the disposal site or the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our ordinary operations, we handle materials that may be regulated as hazardous substances within the meaning of CERCLA, or similar state statutes.

We also generate and accept for disposal from our E&P customers wastes that are subject to the requirements of the Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. RCRA regulates the generation, storage, treatment, transportation and disposal of both non-hazardous and hazardous wastes, but it imposes more stringent requirements on the management of hazardous wastes. In the course of our or our customers' operations, some amounts of ordinary industrial wastes are generated that may be regulated as hazardous wastes. Most E&P waste, if properly handled, is exempt from regulation as a hazardous waste under RCRA. However, it is possible that certain E&P waste now classified as non-hazardous waste and exempt from treatment as hazardous wastes may in the future be designated as "hazardous wastes" under RCRA or other applicable statutes. Repeal or modification of the current RCRA E&P waste exemption or similar exemptions under state law could cause us and our customers to become subject to more rigorous and costly operating and disposal requirements, which could have a material adverse effect on our results of operations and financial position.

We currently own, lease, or operate upon a number of properties that have been used for crude oil and natural gas exploration, development and production support-service activities for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for treatment or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial closure operations to prevent future contamination, the costs of which could be material.

In the course of our operations, some of our storage and process vessels, piping work areas and other equipment may be exposed to naturally occurring radioactive material ("NORM") associated with crude oil and natural gas production. NORM-contaminated scale deposits and other accumulations exhibiting trace levels of naturally occurring radiation in excess of established state standards are subject to special handling and disposal requirements, and any storage and process vessels, piping and work areas affected by NORM may be subject to remediation or restoration requirements. As a result of our operations we may incur costs or liabilities associated with elevated levels of NORM.

Subsurface Injections

Our produced and flowback water underground injection operations are subject to the federal Safe Drinking Water Act ("SDWA") as well as analogous state laws and regulations. Under the SDWA, the EPA established the Underground Injection Control ("UIC") program, which established the minimum program requirements for state and local programs regulating underground injection activities. The UIC program includes requirements for permitting, testing, monitoring, record keeping and reporting of injection well activities, as well as a prohibition against the migration of fluid containing any contaminant into underground sources of drinking water. State regulations require us to obtain a permit from the applicable regulatory agencies to operate our underground injection wells. States may add more stringent restrictions on the operation of injection wells when a permit is renewed or amended, which may require material expenditures at our facilities or impose significant restraints or financial assurances on our operations. Although we monitor the injection process of our wells, any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in suspension of our UIC permit, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource and imposition of liability by third-parties claiming damages for alternative water supplies, property damages and personal injuries. Also, some states have considered laws mandating the recycling of produced and flowback water. If such laws are passed, our E&P customers may divert some produced and flowback water to recycling operations that may have otherwise been disposed of at our facilities, which reduces the demand for our services. In addition, our sales of residual crude oil collected as part of the produced and flowback water injection process may impose liability on us in the event that the entity to which the crude oil was transferred fails to manage and dispose of residual crude oil in accordance with applicable environmental and occupational health and safety laws.

There exists a growing concern amongst the public and federal and state agencies that the injection of produced and flowback water into belowground disposal wells may trigger seismic activity. In 2016, the United States Geological Survey identified Texas as being among six states with areas of increased rates of induced seismicity that could be attributed to fluid injection or crude oil and natural gas extraction. Since that time, the United States Geological Survey indicates that these rates have decreased in these states, although concern continues to exist over quakes arising from induced seismic activities. In response to these concerns, federal and some state agencies are investigating whether such wells have caused increased seismic activity. Also, regulators in some states have adopted, and other states are considering adopting, additional requirements related to seismic safety, including the permitting of disposal wells or otherwise to assess any relationship between seismicity and the use of such wells, which has resulted in some states restricting, suspending or shutting down the use of such injection wells. For example, in Texas, the Texas Railroad Commission has adopted rules governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of crude oil and natural gas in order to address these seismic activity concerns within the state. Also, North Dakota requires a map depicting the area around the location where the disposal well is proposed that depicts any known or suspected faults. The adoption and implementation of any new laws or regulations that restrict our ability to dispose of produced and flowback water gathered from Oasis Petroleum and our other third-party E&P customers, such as by limiting volumes, disposal rates, disposal well locations or otherwise, or by requiring us to shut down disposal wells, could reduce the demand for our produced and flowback water gathering and disposal services and have a material adverse effect on our business, financial condition and results of operations.

Water Discharges

The Federal Water Pollution Control Act ("Clean Water Act") and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as waters of the United States and impose requirements affecting our ability to conduct activities in waters and wetlands. Pursuant to the Clean Water Act and analogous state laws, permits must be obtained to discharge pollutants into state waters or waters of the United States, and individual permits or coverage under general permits must also be obtained to authorize discharges of storm water runoff from certain types of industrial facilities. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon storage tank spill, rupture or leak.

The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers ("Corps"). The EPA and the Corps under the Obama Administration published a final rule in 2015 that attempted to clarify federal jurisdiction under the Clean Water Act over waters of the United States, including wetlands. In 2017, the EPA and the Corps under the Trump Administration agreed to reconsider the 2015 rule and, thereafter, on October 22, 2019, the agencies published a final rule made effective on December 23, 2019, rescinding the 2015 rule. On January 23, 2020, the two agencies issued a final rule re-defining such jurisdiction, which redefinition is narrower than found in the 2015 rule. Upon being published in the Federal Register and the passage of 60 days thereafter, the January 23, 2020 final rule will become effective, at which point the United States will be covered under a single regulatory scheme as it relates to federal jurisdictional reach over waters of the United States. However, there remains the expectation that the January 23, 2020 final rule also will be legally challenged by those who oppose less stringent federal permitting authority in federal district court, following the rule's publication in the Federal Register. To the extent that any challenge to the January 23, 2020 final rule is successful and the 2015 rule or a revised rule expands the scope of the Clean Water Act's jurisdiction in areas where we or our customers conduct operations, such developments could incur increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

The primary federal law related specifically to crude oil spill liability is the Oil Pollution Act of 1990 ("OPA"), which establishes strict, joint and several liability for certain responsible parties in connection to releases of crude oil into waters of the United States. The OPA also imposes ongoing requirements on owners and operators of certain crude oil and natural gas facilities that handle certain quantities of crude oil, including the preparation of crude oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an crude oil spill. If a release of crude oil into the waters of the United States occurred, we could be liable for clean-up costs and various damages under the OPA.

Air Emissions

The federal Clean Air Act ("CAA") and comparable state laws regulate emissions of various air pollutants through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us or our E&P customers to obtain pre-approval for the construction or modification of certain crude oil and natural gas-related projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to restrict, delay or cancel the expansion of our projects as well as our customers' development of crude oil and natural gas projects. Failure to obtain a permit or to comply with permit requirements could result in the imposition of administrative, civil and criminal penalties.

In recent years, there has been increased regulation with respect to air emissions resulting from the crude oil and natural gas sector. For example, in 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone to 70 parts per billion under both the primary and secondary standards. Since that time, the EPA has issued area designations with respect to ground-level ozone and has issued final requirements that apply to state, local and tribal air agencies for implementing the 2015 NAAQS. State implementation of these revised standards for ground-level ozone could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant.

Climate Change

Climate change continues to attract considerable public, political and scientific attention. As a result, numerous regulatory initiatives have been made, and are likely to continue to be made, at the international, national, regional and state levels of government to monitor and limit existing emissions of greenhouse gases ("GHGs") as well as to restrict or eliminate such future emissions. These regulatory 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. Additionally, the threat of climate change has resulted in increasing political, litigation and financial risks associated with the production of fossil fuels and emission of GHGs. The adoption and implementation of any federal or state legislation, regulations or executive orders or the occurrence of any litigation or financial developments that impose more stringent requirements or bans on GHG-emitting production activities or locations where such production activities may occur, impose liabilities for past conduct relating to GHG-emitting production activities or limit or eliminate sources of financing for on-going production operations could require our E&P customers to incur increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and natural gas that, in turn, could reduce demand for our products and services. See "Item 1A. Risk Factors – Our and our customers' operations are subject to a number of risks arising out of the threat of climate change, including regulatory, political, litigation and financial risks, which could result in increased operating and capital costs for our customers and reduced demand for the products and services we provide" for additional information relating to risks arising out of climate change, including the emission of GHGs.

Hydraulic Fracturing

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, including crude oil and natural gas, from low permeability formations, including shales. The process involves the injection of water, sand or other proppant and chemical additives under pressure into targeted formations to fracture the surrounding rock and stimulate production. Our E&P customers regularly use hydraulic fracturing as part of their operations.

Hydraulic fracturing is typically regulated by state crude oil and natural gas commissions and similar agencies but federal agencies have conducted investigations or asserted regulatory authority over certain aspects of the process. 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 some circumstances. Additionally, the EPA has asserted regulatory authority pursuant to the SDWA UIC program over hydraulic fracturing activities to the extent involving the use of diesel and issued guidance covering such activities; has issued an Advance Notice of Proposed Rulemaking to collect data on chemicals used in hydraulic fracturing operations under Section 8 of the Toxic Substances Control Act; and published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional crude oil and natural gas extraction facilities to publicly owned wastewater treatment plants.

From time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing, including the underground disposal of fluids or propping agents associated with such fracturing activities and the disclosure of the chemicals used in the fracturing process. However, concern over the threat of climate change has resulted in the making of pledges by certain candidates seeking the office of the President of the United States in 2020 to ban hydraulic fracturing of oil and natural gas wells.

In addition, a number of states, including North Dakota, Montana and Texas, where we operate, have adopted, and other states are considering adopting, regulations imposing new permitting, disclosure, disposal and well construction requirements on hydraulic fracturing operations. States could impose moratoriums or elect to place certain prohibitions on hydraulic fracturing, similar to the approach taken by the States of Maryland, New York and Vermont. Also, local governments could seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular.

If new federal, state or local restrictions or bans on hydraulic fracturing are adopted in areas where our E&P customers operate, our E&P customers' fracturing activities could become subject to additional permit requirements, reporting requirements, operational restrictions, permitting delays, restrictions or cancellations in their production activities or additional costs. Any such laws or regulations could adversely affect the determination of whether a well is commercially viable and reduce the amount of crude oil and natural gas that our customers are ultimately able to produce in commercial quantities, and thus significantly affect our business. Such laws and regulations could also materially increase our cost of business by more strictly regulating how hydraulic fracturing wastes are handled or disposed, which could have an indirect adverse impact on the demand for our produced and flowback water gathering and disposal services.

National Environmental Policy Act

Crude oil and natural gas E&P activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the U.S. Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. The process involves the preparation of either an environmental assessment or a more detailed environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action will have a significant impact on the human environment. The NEPA process involves public input through comments, which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the court system by process participants. This process may result in delaying, limiting or prohibiting the permitting and development of projects or performance of midstream services, increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of existing leases.

Endangered Species

The Endangered Species Act ("ESA") and comparable state laws restrict crude oil and natural gas-related activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the Migratory Birds Treaty Act. To the extent species that are listed under the ESA or similar state laws live in the areas where our operations and our E&P customers' operations are conducted, our and our customers' abilities to conduct or expand operations and construct facilities could be limited or could force us or our customers to incur significant additional costs. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for crude oil and natural gas development. In addition, the U.S. Fish and Wildlife Service may make new determinations on the listing of species as endangered or threatened under the ESA. The designation of previously undesignated species as endangered or threatened could cause us to incur additional costs or cause our customers' operations to become subject to operating restrictions or bans or limit future development activity in affected areas, which developments could reduce demand for our gathering, transportation, processing and disposal services.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupational Safety and Health Act and comparable state laws that regulate the protection of employee health and safety. In addition, OSHA's implementation of the hazard communications standard, the EPA's implementation of community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act, and comparable state statutes require that information about hazardous materials used or produced in our operations be maintained and provided to employees, state and local government authorities and citizens. These laws and regulations are subject to frequent changes. Failure to comply with these laws could lead to the assertion of third-party claims against us, civil or criminal fines and changes in the way we operate our facilities that could have an adverse effect on our financial position.

Other Regulation of the Crude Oil and Natural Gas Industry

The crude oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the crude oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the crude oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although changes to the regulatory burden on the crude oil and natural gas industry could affect the demand for our services, we would not expect to be affected any differently or to any greater or lesser extent than other companies in the industry with similar operations.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Historically, our compliance costs with applicable laws and regulations have not had a material adverse effect on our financial position, cash flow and results of operations; however, new laws and regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement may occur and, thus, there can be no assurance that such costs will not be material in the future. Additionally, environmental incidents such as spills or other releases may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the crude oil and natural gas industry are regularly considered by Congress, the states, FERC and the courts. We cannot predict when or whether any such proposals may be finalized and become effective.

Regulation of Transportation of Crude Oil

Only the crude oil transportation system connecting the Wild Basin area to the Johnson's Corner market center transports crude oil in interstate commerce. FERC regulates interstate crude oil pipeline transportation rates under the Interstate Commerce Act of 1887 as modified by the Elkins Act ("ICA"), the Energy Policy Act of 1992 and the rules promulgated under those laws. In general, interstate crude oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for crude oil pipelines that allows a pipeline to increase its rates annually up to prescribed ceiling levels that are tied to changes in the Producer Price Index, without making a cost of service filing. Many existing pipelines utilize the FERC crude oil index to change transportation rates annually every July 1, and our Bighorn DevCo Johnson's Corner line will utilize the FERC crude oil index beginning on July 1, 2022. Every five years, FERC reviews the appropriateness of the index level in relation to changes in industry costs. Most recently, on December 17, 2015, FERC established a new price index for the five-year period commencing July 1, 2016 and ending June 30, 2021, in which common carriers charging indexed rates are permitted to adjust their indexed ceilings annually by Producer Price Index plus 1.23%.

On March 15, 2018, in a set of related issuances, FERC addressed treatment of federal income tax allowances in regulated entity rates. FERC issued a Revised Policy Statement on Treatment of Income Taxes ("Revised Policy Statement") stating that, among other things and with respect to crude oil and refined products pipelines subject to FERC jurisdiction, the pipeline is required to reflect the impacts to its cost of service from the Revised Policy Statement and the Tax Cuts and Jobs Act of 2017 on Page 700 of FERC Form No. 6. This information will be used by FERC in its next five-year review of the crude oil pipeline index to generate the index level to be effective July 1, 2021, thereby including the effect of the Revised Policy Statement and the Tax Cuts and Jobs Act of 2017 in the determination of indexed rates prospectively, effective July 1, 2021. FERC's establishment of a just and reasonable rate, including the determination of the appropriate crude oil pipeline index, is based on many components, and tax-related changes will affect two such components, the allowance for income taxes and the amount for accumulated deferred income taxes, while other pipeline costs also will continue to affect FERC's determination of the appropriate pipeline index. Accordingly, depending on FERC's application of its indexing rate methodology for the next five-year term of index rates, the Revised Policy Statement and tax effects related to the Tax Cuts and Jobs Act of 2017 may impact our revenues associated with any transportation services we may provide pursuant to cost-of-service based rates in the future, including indexed rates.

Under the ICA, FERC or interested persons may challenge existing or proposed new or changed rates, services, or terms and conditions of service. Under certain circumstances, FERC could limit a regulated pipeline's ability to charge rates until completion of an investigation during which FERC could find that the new or changed rate is unlawful. In contrast, FERC has clarified that initial rates and terms of service agreed upon with committed shippers in a transportation services agreement are not subject to protest or a cost-of-service analysis where the pipeline held an open season offering all potential shippers service on the same terms.

A successful rate challenge could result in a regulated pipeline paying refunds of revenue collected in excess of the just and reasonable rate, together with interest for the period that the rate was in effect, if any. FERC may also order a pipeline to reduce its rates prospectively, and may require a regulated pipeline to pay shippers reparations retroactively for rate overages for a period of up to two years prior to the filing of a complaint. FERC also has the authority to change terms and conditions of service if it determines that they are unjust or unreasonable or unduly discriminatory or preferential. We may also be required to respond to requests for information from government agencies, including compliance audits conducted by FERC.

Regulation of Transportation of Natural Gas

Historically, the transportation of natural gas in interstate commerce has been regulated by FERC under the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA") and regulations issued under those statutes. Gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states onshore and in state waters. Although FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, FERC's determinations as to the classification of facilities is done on a case by case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that our customers produce.

Other Federal Laws and Regulations Affecting our Industry

Energy Policy Act of 2005. On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 ("EPAct 2005"). EPAct 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. EPAct 2005 provides FERC with the power to assess civil penalties of up to $1,291,894 per day for violations of the NGA, adjusted annually for inflation, and increases FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1,291,894 per violation per day, adjusted annually for inflation. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of EPAct 2005, and subsequently denied rehearing. The rule makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) engage in any act, practice or course of business that operates as a fraud or deceit upon any person. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order No. 704, as described below. The anti-manipulation rules and enhanced civil penalty authority reflect an expansion of FERC’s NGA enforcement authority. Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

State Regulation

States regulate the drilling for crude oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of crude oil and natural gas resources. For example, in 2014, the North Dakota Department Industrial Commission (“NDIC”) adopted Order No. 24665 (the “2014 Order”), pursuant to which the agency adopted legally enforceable “gas capture percentage goals” targeting the capture of natural gas produced in the state between October 1, 2014 and October 1, 2020. Modification of the 2014 Order by the NDIC in late 2015 resulted in revised gas capture percentage goals of 88% and 91% required to be achieved by November 1, 2018 and November 1, 2020, respectively. Recently, in November 2018, the NDIC considered revising its 2018 and 2020 gas capture percentage goals but elected to retain those standards; however, the NDIC revised the flaring program’s policy goals such that the crude oil and gas exploration and production industry has more flexibility in removing certain gas volumes from consideration in calculating compliance with the state’s gas capture percentage goals. The NDIC continues to adhere to other aspects of the modified 2014 Order, including development of Gas Capture Plans that provide measures for reducing the amount of natural gas flared by those operators so as to be consistent with the agency’s gas capture percentage goals. Also, wells must continue to meet or exceed the NDIC’s gas capture percentage goals on a per-well, per-field, county or statewide basis. If an operator is unable to attain the applicable gas capture percentage goal at maximum efficient rate, wells will be restricted in production to 200 barrels of crude oil per day if at least 60% of the monthly volume of associated natural gas produced from the well is captured, or otherwise crude oil production from such wells shall not exceed 100 barrels of crude oil per day. However, the NDIC will consider flexibility to these production restrictions, by means of temporary exemptions, for other types of extenuating circumstances after notice and hearing if the effect of such flexibility is a significant net increase in gas capture within one year of the date such relief is granted. Monetary penalty provisions also apply under this policy in the event an operator not meeting the gas capture percentage goals fails to timely file for a hearing with the NDIC upon being unable to meet such percentage goals or if the operator fails to timely implement production restrictions once below the applicable percentage goals. In late 2019, the overall natural gas capture rate for producers in North Dakota failed to attain the current statewide gas capture rate of 88%, and the gas capture rate will increase to 91% on November 1, 2020. To the extent that our E&P customers attempt to, but cannot comply with these gas capture requirements, those customers could incur increased compliance costs or restrictions on future production, which development could reduce demand for our services and have an adverse effect on our results of operations.

States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure our unitholders that they will not do so in the future. The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Employees

We do not have any employees. The officers of our General Partner, who are also officers of Oasis Petroleum, manage our operations and activities. As of December 31, 2019, Oasis Petroleum employed approximately 102 people who provide direct, full-time support to our operations. All of the employees that conduct our business are employed by Oasis Petroleum and its affiliates. We believe that Oasis Petroleum and its affiliates have a satisfactory relationship with those employees.

Office

The principal office of our Partnership is located at 1001 Fannin Street, Suite 1500, Houston, Texas 77002.

Available information

We are required to file annual, quarterly and current reports and other information with the United States Securities and Exchange Commission (“SEC”). Our filings with the SEC are available to the public from commercial document retrieval services and at the SEC’s website at http://www.sec.gov. Our common stock is listed and traded on The NASDAQ Stock

Market LLC (“Nasdaq”) under the symbol “OMP.” We make available on our website at http://www.oasismidstream.com all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website is not incorporated by reference into this Annual Report on Form 10-K.

Other information, such as presentations, the charter of the Audit Committee and the Code of Business Conduct and Ethics are available on our website, http://www.oasismidstream.com, under “Investor Relations — Corporate Governance” and in print to any unitholders who provide a written request to the Corporate Secretary at 1001 Fannin Street, Suite 1500, Houston, Texas 77002.

Our Code of Business Conduct and Ethics applies to all directors, officers and employees, including the Chief Executive Officer and Chief Financial Officer. Within the time period required by the SEC and Nasdaq, as applicable, we will post on our website any modification to the Code of Business Conduct and Ethics any waivers applicable to senior officers who are defined in the Code of Business Conduct and Ethics, as required by the Sarbanes-Oxley Act of 2002 (“Sarbanes-Oxley Act”).

Item 1A. Risk Factors

Limited partner interests are inherently different from the 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 a similar business. You should carefully consider the following risk factors and all other information set forth in this Annual Report on Form 10-K.

If any of the following risks were to occur, our business, financial condition, results of operations, cash flows and ability to make cash distributions could be materially adversely affected. In that case, we may not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and our unitholders could lose all or part of their investment. In addition, the current economic and political environment intensifies many of these risks.

Risks Related to Our Business

Because a substantial majority of our revenue currently is, and over the long term is expected to be, derived from Oasis Petroleum, any development that materially and adversely affects Oasis Petroleum's operations, financial condition or market reputation could have a material and adverse impact on us.

We are substantially dependent on Oasis Petroleum as our most significant current customer, and we expect to derive a substantial majority of our revenues from Oasis Petroleum for the foreseeable future. As a result, any event, whether in our areas of operation or otherwise, that adversely affects Oasis Petroleum's production, drilling and completion schedule, financial condition, leverage, market reputation, liquidity, results of operations or cash flows may adversely affect our revenues and distributable cash. Accordingly, we are indirectly subject to the business risks of Oasis Petroleum, including, among others:

- a reduction in or slowing of Oasis Petroleum's anticipated drilling and production schedule, which would directly and adversely impact demand for our midstream infrastructure;
- the volatility of crude oil and natural gas prices, which could have a negative effect on the value of Oasis Petroleum's properties, its drilling programs or its ability to finance its operations;
- changes in regulations or statutes applicable to us or Oasis Petroleum, which could have a negative effect on the value of our facilities or services or Oasis Petroleum's properties, its drilling programs or its ability to finance its operations;
- the availability of capital on an economic basis to fund Oasis Petroleum's exploration and development activities;
- Oasis Petroleum's ability to replace reserves;
- Oasis Petroleum's ability to market and deliver commodities downstream of our systems;
- Oasis Petroleum's drilling and operating risks, including potential environmental liabilities;
- severe weather that may adversely affect Oasis Petroleum's production and operations;
- limitations on Oasis Petroleum's operations resulting from its debt restrictions and financial covenants;
- adverse effects of governmental and environmental regulation; and
- losses from pending or future litigation.

In addition, although Oasis Petroleum has dedicated certain acreage to us under each of our commercial agreements with Oasis Petroleum, these commercial agreements do not contain any material minimum volume commitments. Accordingly, if commodity prices decline substantially for a prolonged period, Oasis Petroleum has the ability to substantially reduce its drilling and completion expenditures, which would decrease our throughput volumes from Oasis Petroleum and related revenue streams under our commercial agreements.

Further, we are subject to the risk of non-payment or non-performance by Oasis Petroleum, including with respect to our long-term contracts for natural gas gathering, compression, processing and gas lift; crude oil gathering, stabilization, blending, storage and transportation; produced and flowback water gathering and disposal; and freshwater distribution. If Oasis Petroleum were to default under any of these contracts, we would have the contractual right to bring suit against Oasis Petroleum to enforce the terms of such contract, and there can be no assurance that we would obtain a recovery, or that any such recovery that would fully compensate us for the consequence of such default. We neither can predict the extent to which Oasis Petroleum's business would be impacted if conditions in the energy industry were to deteriorate, nor can we estimate the impact such conditions would have on Oasis Petroleum's ability to execute its drilling and development program or perform under our commercial agreements. Any material non-payment or non-performance by Oasis Petroleum could reduce our ability to make distributions to our unitholders.

Also, due to our relationship with Oasis Petroleum, our ability to access the capital markets, or the pricing or other terms of any capital markets transactions, may be adversely affected by any impairment to Oasis Petroleum's financial condition or adverse changes in its credit ratings. Further, if we were to seek a credit rating in the future, our credit rating may be adversely affected by Oasis Petroleum's leverage or its dependence on the cash flows from us to service its indebtedness, as credit rating agencies such as Standard & Poor's Ratings Services and Moody's Investors Service may consider the credit profile of Oasis Petroleum and its affiliates because of their ownership interest in and control of us.

Any material limitation on our ability to access capital as a result of our relationship with Oasis Petroleum or adverse changes at Oasis Petroleum could limit our ability to obtain future financing under favorable terms, or at all, or could result in increased financing costs in the future. Similarly, material adverse changes at Oasis Petroleum 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.

In the event Oasis Petroleum elects to sell acreage that is dedicated to us to a third party, the third party's financial condition could be materially worse than Oasis Petroleum, and thus we could be subject to nonpayment or nonperformance by the third party.

In the event Oasis Petroleum elects to sell acreage that is dedicated to us to a third party, the third party's financial condition could be materially worse than Oasis Petroleum's. In such a case, we may be subject to risks of loss resulting from nonpayment or nonperformance by the third party, which risks may increase during periods of economic uncertainty. Furthermore, the third party may be subject to their own operating risks, which increases the risk that they may default on their obligations to us. Any material nonpayment or nonperformance by the third party could reduce our ability to make distributions to our unitholders.

We may not generate 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 the minimum quarterly distribution to our unitholders.

In order to make our minimum quarterly distribution of $0.3750 per common unit and subordinated unit per quarter, or $1.50 per unit per year, we will require available cash of approximately $12.7 million per quarter, or approximately $50.7 million per year, based on the common units and subordinated units outstanding as of February 19, 2020. We may not generate sufficient cash flows to support the payment of the minimum quarterly distribution to our unitholders.

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:

- Oasis Petroleum's and our third-party customers' ability to fund their drilling programs in our areas of operation;
- market prices of crude oil and natural gas and their effect on Oasis Petroleum's and third parties' drilling schedule, as well as produced volumes;
- the fees we charge, and the margins we realize, from our midstream infrastructure business;
- the volumes of natural gas we gather, compress and process, the volumes of crude oil we gather, blend, stabilize and transport, the volumes of produced and flowback water we collect or dispose of and the volumes of freshwater we distribute;
- our ability to make acquisitions of other midstream infrastructure assets, including any of the Subject Assets, or other assets that complement or diversify our operations;
- the level of competition from other companies;
- costs associated with leaks or accidental releases of hydrocarbons or produced and flowback water into the environment, as a result of human error or otherwise;
- adverse weather conditions, natural disasters, vandalism and acts of terror;
- the level of our operating, maintenance and general and administrative costs;
- governmental regulations, including changes in governmental regulations, in our and our customers' industries; and
- prevailing economic and market conditions.

In addition, the actual amount of our distributable cash will depend on other factors, including:

- the level and timing of capital expenditures we make;
- our debt service requirements and other liabilities;
- the level of our operating costs and expenses and the performance of our various facilities;
- our ability to make borrowings under the revolving credit facility (as defined below) to pay distributions;
- fees and expenses of our General Partner and its affiliates (including Oasis Petroleum) we are required to reimburse; and
- other business risks affecting our cash levels.

Because of the natural decline in production from existing wells, our success depends, in part, on Oasis Petroleum's ability to replace declining production and our ability to secure new sources of production from Oasis Petroleum or third parties. Any decrease in Oasis Petroleum's production could adversely affect our business and operating results.

The level of crude oil and natural gas volumes handled by our midstream systems depends on the level of production from crude oil and natural gas wells dedicated to our midstream systems, which may be less than expected and which will naturally decline over time. In addition, the demand for our produced and flowback water services is directly correlated with the level of production from the crude oil and natural gas wells connected to our midstream system and the demand for our freshwater services is largely correlated with the level of our customers' capital spending programs. To the extent Oasis Petroleum reduces its activity or otherwise ceases to drill and complete wells within our acreage dedication, our revenues will be directly and adversely affected. In order to maintain or increase our expected cash flows, we will need to obtain additional throughput volumes from Oasis Petroleum or third parties. The primary factors affecting our ability to obtain such additional throughput volumes include (i) the success of Oasis Petroleum's and our third-party customers' drilling activities in our areas of operation and (ii) our ability to acquire additional well connections from Oasis Petroleum or third parties. Therefore, our midstream infrastructure business is dependent upon active development in our areas of operation.

We have no control over Oasis Petroleum's or other producers' level of development and completion 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 Oasis Petroleum or other producers or their development plan decisions, which are affected by, among other things:

- the availability and cost of capital;
- prevailing and projected crude oil and natural gas prices;
- the proximity, capacity, cost and availability of gathering and transportation facilities, and other factors that result in differentials to benchmark prices;
- demand for crude oil and natural gas;
- levels of reserves;
- geologic considerations;
- environmental or other governmental laws and regulations, including the availability of drilling permits, the regulation of hydraulic fracturing, the availability of certain federal income tax deductions with respect to crude oil and natural gas exploration and development, and state taxes on crude oil and natural gas extraction;
- shareholder activism or activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development and production of crude oil and natural gas; and
- the costs of producing crude oil and natural gas and the availability and costs of drilling rigs and other equipment.

Fluctuations in energy prices can also greatly affect the development of reserves. In general terms, the prices of crude oil, natural gas 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. These factors include worldwide economic conditions, weather conditions and seasonal trends, the levels of domestic production and consumer demand, the availability of imported crude oil and liquefied natural gas (" LNG"), the availability of transportation systems with adequate capacity, the volatility and uncertainty of regional pricing differentials, the price and availability of alternative fuels, the effect of energy conservation measures, the nature and extent of governmental regulation and taxation, and the anticipated future prices of crude oil, natural gas, LNG and other commodities. Declines in commodity prices could have a negative impact on Oasis Petroleum's development and production activity, and if sustained, could lead to a material decrease in such activity. Sustained reductions in development or production activity in our areas of operation could lead to reduced utilization of our services.

In addition, substantially all of Oasis Petroleum's crude oil and natural gas production is sold to purchasers under contracts with market-based prices. The actual prices realized from the sale of crude oil and natural gas differ from the quoted NYMEX West Texas Intermediate and NYMEX Henry Hub prices, respectively, as a result of location differentials. Location differentials to NYMEX West Texas Intermediate and NYMEX Henry Hub prices, also known as basis differentials, result from variances in regional crude oil and natural gas prices compared to NYMEX West Texas Intermediate and NYMEX Henry Hub prices as a result of regional supply and demand factors. Oasis Petroleum may experience differentials to NYMEX West Texas Intermediate and NYMEX Henry Hub prices in the future, which may be material.

Due to these and other factors, even if reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. If reductions in development activity result in our inability to maintain the current levels of throughput volumes on our midstream systems, those reductions could reduce our revenue and cash flows and adversely affect our ability to make cash distributions to our unitholders. If we are unable to generate sufficient distributable cash in future periods, we may not be able to support the payment of the full minimum quarterly distribution or any amount on our common units or subordinated units, in which event the market price of our common units may decline materially.

Substantially all of our assets are controlling ownership interests in our DevCos. Because our interests in our DevCos represent almost all of our cash-generating assets, our cash flows will depend entirely on the performance of our DevCos and their ability to distribute cash to us.

We have a holding company structure, and the primary source of our earnings and cash flows consists exclusively of the earnings of and cash distributions from our DevCos. Therefore, our ability to make quarterly distributions to our unitholders will be almost entirely dependent upon the performance of our DevCos and their ability to distribute funds to us. We are the sole managing member of each of our DevCos, giving us the right to control and manage our DevCos.

The limited liability company agreement governing each DevCo requires the managing member of such DevCo to cause it to distribute all of its available cash each quarter, less the amounts of cash reserves that such managing member determines are necessary or appropriate in its reasonable discretion to provide for the proper conduct of such DevCo's business.

The amount of cash each DevCo generates from its operations will fluctuate from quarter to quarter based on events and circumstances and other factors, as will the actual amount of cash each DevCo will have available for distribution to its members, including us.

We serve customers who are involved in drilling for, producing and transporting crude oil and natural gas. Adverse developments affecting the crude oil and natural gas industry or drilling activity, including sustained low crude oil or natural gas prices, a decline in crude oil or natural gas prices, reduced demand for crude oil and natural gas products and increased regulation of drilling and production, could have a material adverse effect on our results of operations.

Our midstream infrastructure business depends on our customers' willingness to make operating and capital expenditures to develop and produce crude oil and natural gas in the United States. A reduction in drilling activity generally results in decreases in the volumes of crude oil, natural gas and produced and flowback water produced, which adversely impacts our revenues. Therefore, if these expenditures decline, our business is likely to be adversely affected.

Our customers' willingness to engage in drilling and production of crude oil and natural gas depends largely upon prevailing industry conditions that are influenced by numerous factors over which our management has no control, such as:

- the supply of and demand for crude oil and natural gas;
- the level of prices, and expectations about future prices, of crude oil and natural gas;
- the cost of exploring for, developing, producing and delivering crude oil and natural gas, including fracturing services;
- the expected rate of decline of current crude oil and natural gas production;
- the discovery rates of new crude oil and natural gas reserves;
- available pipeline and other transportation capacity;
- lead times associated with acquiring equipment and products and availability of personnel;
- weather conditions, including hurricanes, tornadoes, wildfires, drought or man-made disasters that can affect crude oil and natural gas operations over a wide area, as well as local weather conditions in the Bakken Shale region of the Williston Basin in North Dakota that can have a significant impact on drilling activity in that region;
- regulations regarding flaring which may significantly increase the expenses associated with production;
- domestic and worldwide economic conditions;
- contractions in the credit market;
- political instability in certain crude oil and natural gas producing countries;
- the continued threat of terrorism and the impact of military and other action, including military action in the Middle East;
- governmental regulations, including income tax laws or government incentive programs relating to the crude oil and natural gas industry and the policies of governments regarding the exploration for and production and development of their crude oil and natural gas reserves;
- the level of crude oil production by non-OPEC countries and the available excess production capacity within OPEC;
- crude oil refining capacity and shifts in end-customer preferences toward fuel efficiency;
- potential acceleration in the development, and the price and availability, of alternative fuels;
- the availability of water resources for use in hydraulic fracturing operations;

- public pressure on, and legislative and regulatory interest in, federal, state and local governments to ban, stop, significantly limit or regulate hydraulic fracturing operations;
- technical advances affecting energy consumption;
- the access to and cost of capital for crude oil and natural gas producers;
- merger and divestiture activity among crude oil and natural gas producers; and
- the impact of changing regulations and environmental and occupational health and safety rules and policies.

Our ROFO/ROFR on Oasis Petroleum's retained assets is subject to risks and uncertainty, and ultimately we may not acquire any of those assets.

At the closing of the initial public offering, Oasis Petroleum granted us a ROFO, which converts into a ROFR, applicable to a successor upon a change of control of Oasis Petroleum, with respect to its retained interests in two of our DevCos and any other midstream assets that Oasis Petroleum builds with respect to its acreage at the time of our initial public offering and elects to sell in the future. The consummation and timing of any acquisition by us of the assets covered by our ROFO or ROFR, as applicable, will depend upon, among other things, our ability to reach an agreement with Oasis Petroleum on price and other terms and our ability to obtain financing on acceptable terms. Moreover, Oasis Petroleum is only obligated to offer to sell us the Subject Assets if Oasis Petroleum decides to monetize such assets. Accordingly, we can provide no assurance whether, when or on what terms we will be able to successfully consummate any future acquisitions pursuant to our ROFO or ROFR, as applicable, and Oasis Petroleum is under no obligation to accept any offer that we may choose to make or to enter into any commercial agreements with us. Additionally, we may decide not to exercise our ROFO or ROFR, as applicable, when we are permitted to do so, and our decision will not be subject to unitholder approval. Finally, both the ROFO and the ROFR will terminate in the event Oasis Petroleum elects to sell our General Partner to a third party (other than in connection with a change of control of Oasis Petroleum).

Certain of our commercial agreements with Oasis Petroleum provide it with termination rights under certain circumstances. In the event Oasis Petroleum were to exercise its termination rights under such circumstances, it may have a material adverse effect on our business, results of operations or financial position.

Certain of the commercial agreements that the Partnership has entered into with subsidiaries of Oasis Petroleum contain provisions that, upon (i) assignment of the agreement by the Partnership to a party that is not an affiliate of the Partnership or OMS or (ii) a change of control of the Partnership that results in the Partnership or the applicable DevCo(s) no longer being controlled by Oasis Petroleum, OPNA, OPM and/or OMS, as applicable, grant Oasis Petroleum the right to renegotiate the terms of such agreement with the Partnership. In the event that the Partnership and Oasis Petroleum are unable to agree on mutually agreeable amendments (if any), Oasis Petroleum will have the right to terminate the agreement. The substantial majority of the Partnership's revenues are derived from operations performed pursuant to these agreements. If the foregoing circumstances were to occur and Oasis Petroleum were to cause the termination of any or all of such commercial agreements, it may have a material adverse effect on the Partnership's business, results of operations or financial position.

Due to our lack of asset and geographic diversification, adverse developments in the areas in which we are located could adversely impact our financial condition, results of operations and cash flows and reduce our ability to make distributions to our unitholders.

Our midstream infrastructure assets are located in the Williston Basin in North Dakota and Montana and the Delaware Basin in Texas. As a result of this concentration, our financial condition, results of operations and cash flows are significantly dependent upon the demand for our midstream infrastructure assets in these areas, and we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in these areas caused by governmental regulation, market limitations, or other adverse events at one of our midstream infrastructure assets. As we are substantially dependent on Oasis Petroleum, as our largest customer, if Oasis Petroleum were to shift the geographic focus of its drilling activities away from the Williston Basin or Delaware Basin, there could be a reduction in the development activity tied to our assets, which could reduce our revenue and cash flows and adversely affect our ability to make cash distributions to our unitholders.

We cannot predict the rate at which our customers will develop acreage that is dedicated to us or the areas they will decide to develop.

Our acreage dedication and commitments from Oasis Petroleum cover midstream services in a number of areas that are at the early stages of development, in areas that Oasis Petroleum is still determining whether to develop, and in areas where we may have to acquire operating assets from third parties. In addition, Oasis Petroleum owns acreage in areas that are not dedicated to us. We cannot predict which of these areas Oasis Petroleum will determine to develop and at what time. Oasis Petroleum may decide to explore and develop areas in which we have a smaller operating interest in the midstream assets that service that area, or where the acreage is not dedicated to us, rather than areas in which we have a larger operating interest in the midstream assets that service that area. Oasis Petroleum's decision to develop acreage that is not dedicated to us or that we have a smaller operating interest in may adversely affect our business, financial condition, results of operations, cash flows and ability to make cash distributions. Likewise, we have no ability to influence when or where an unaffiliated third-party customer elects to develop acreage that is dedicated to us.

To the extent Oasis Petroleum shifts the focus of its development away from the acreage dedicated to us and to other areas of operations where we do not have assets or acreage dedications, our results of operations and distributable cash could be adversely affected. In addition, because of contractual dedications to third-party crude oil and natural gas gathering companies, our opportunity to purchase additional midstream assets from Oasis Petroleum is generally limited to midstream assets Oasis Petroleum may develop in the City of Williston, Painted Woods, Missouri, Dublin, Target, and Far North Cottonwood areas and other areas Oasis Petroleum may develop in the future.

Under the terms of our long-term contracts with Oasis Petroleum for natural gas gathering, compression, processing and gas lift; crude oil gathering, stabilization, blending, storage and transportation; produced and flowback water gathering and disposal; and freshwater distribution, we cannot guarantee that Oasis Petroleum will focus on and continue to develop the acreage subject to our dedication.

To the extent Oasis Petroleum shifts the focus of its operations away from the areas dedicated to us and to its other areas where we do not have assets or operations, our business, financial condition, results of operations and ability to make cash distributions to our unitholders could be adversely affected.

In addition, at the time of our initial public offering, Oasis Petroleum had acreage dedications to third-party midstream service providers for natural gas services and for crude oil services. Accordingly, our ROFO or ROFR, as applicable, on additional midstream assets from Oasis Petroleum would be applicable only if Oasis Petroleum elects to build and sell assets in these areas when the existing third-party dedication lapses. As a result, our opportunity to acquire crude oil and gas gathering, processing and transportation assets from Oasis Petroleum, including pursuant to our ROFO or ROFR, as applicable, is generally limited, in the near term, to assets Oasis Petroleum may develop on its acreage at the time of our initial public offering in the City of Williston, Painted Woods, Missouri, Dublin, Target, and Far North Cottonwood areas. If Oasis Petroleum does not develop midstream assets in these areas or elects not to offer them for sale, our ability to grow through the acquisition of additional midstream assets from Oasis Petroleum may be significantly and adversely impacted.

In the event Oasis Petroleum elects to sell acreage that is dedicated to us to a third party, the third party’s financial condition could be materially worse than Oasis Petroleum’s financial condition. In such a case, we may be subject to risks of loss resulting from nonpayment or nonperformance by the third party, which risks may increase during periods of economic uncertainty. Furthermore, the third party may be subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. Any material nonpayment or nonperformance by the third party could reduce our ability to make distributions to our unitholders.

We may be unable to grow by acquiring from Oasis Petroleum the retained non-controlling interests in two of our DevCos or any other midstream assets that Oasis Petroleum builds with respect to its acreage and elects to sell in the future, which could limit our ability to increase our distributable cash.

Part of our strategy for growing our business and increasing distributions to our unitholders is dependent upon our ability to make acquisitions that increase our distributable cash. Part of the acquisition component of our growth strategy is based upon our expectation of future divestitures by Oasis Petroleum to us of retained, acquired or developed midstream assets and portions of its retained, non-controlling interests in two of our DevCos. While we are beneficiaries of our ROFO or ROFR, as applicable, under our Omnibus Agreement, Oasis Petroleum is under no obligation to sell its retained interests in two of our DevCos or to offer to sell us any additional midstream assets, we are under no obligation to buy any additional interests or assets from Oasis Petroleum and we do not know when or if Oasis Petroleum will decide to sell its retained interests in two of our DevCos or make any offers to sell assets to us. We may never purchase all or any portion of the retained, non-controlling interests in two of our DevCos or any other midstream assets from Oasis Petroleum for several reasons, including the following:

- Oasis Petroleum may choose not to sell these non-controlling interests or assets;
- we may not accept offers for these assets or make acceptable offers for these equity interests;
- we and Oasis Petroleum may be unable to agree to terms acceptable to both parties;
- we may be unable to obtain financing to purchase these non-controlling interests or assets on acceptable terms or at all; or
- we may be prohibited by the terms of our debt agreements (including our revolving credit facility, as defined below) or other contracts from purchasing some or all of these non-controlling interests or assets, and Oasis Petroleum may be prohibited by the terms of its debt agreements or other contracts from selling some or all of these non-controlling interests or assets. If we or Oasis Petroleum must seek waivers of such provisions or refinance debt governed by such provisions in order to consummate a sale of these non-controlling interests or assets, we or Oasis Petroleum may be unable to do so in a timely manner or at all.

Each of these factors may also result in our inability to exercise our right under the ROFR with any successor to Oasis Petroleum following a change of control of Oasis Petroleum. We do not know when or if Oasis Petroleum will decide to sell all or any portion of its non-controlling interests or will offer us any portion of its assets, and we can provide no assurance that we will be able to successfully consummate any future acquisition of all or any portion of such non-controlling interests in two of our DevCos or assets. Furthermore, if Oasis Petroleum reduces its ownership interest in us, it may be less willing to sell to us its retained non-controlling interests in our DevCos or any other midstream assets.

In addition, except for our ROFO or ROFR, as applicable, there are no restrictions on Oasis Petroleum's ability to transfer its non-controlling interests in two of our DevCos or any of its midstream assets to a third party or non-controlled affiliate. Finally, both the ROFO and the ROFR will terminate if Oasis Petroleum elects to sell our General Partner to a third party. If we do not acquire all or a significant portion of the non-controlling interests in two of our DevCos held by Oasis Petroleum or other midstream assets from Oasis Petroleum (or, as applicable, any successor to Oasis Petroleum), our ability to grow our business and increase our cash distributions to our unitholders may be significantly limited.

An unfavorable resolution of the Mirada Litigation could have a material adverse effect on our business, financial condition, results of operations and cash flows.

On March 23, 2017, Mirada Energy, LLC, Mirada Wild Basin Holding Company, LLC and Mirada Energy Fund I, LLC (collectively, "Mirada") filed a lawsuit against Oasis Petroleum, OPNA and OMS, seeking monetary damages in excess of $100.0 million, declaratory relief, attorneys' fees and costs (Mirada Energy, LLC, et al. v. Oasis Petroleum North America LLC, et al.; in the 334th Judicial District Court of Harris County, Texas; Case Number 2017-19911). In its original lawsuit Mirada asserts that it is a working interest owner in certain acreage owned and operated by Oasis Petroleum in Wild Basin. Specifically, Mirada asserts that Oasis Petroleum has breached certain agreements by: (1) failing to allow Mirada to participate in Oasis Petroleum's midstream operations in Wild Basin; (2) refusing to provide Mirada with information that Mirada contends is required under certain agreements and failing to provide information in a timely fashion; (3) failing to consult with Mirada and failing to obtain Mirada's consent prior to drilling more than one well at a time in Wild Basin; and (4) overstating the estimated costs of proposed well operations in Wild Basin. Mirada seeks a declaratory judgment that OPNA be removed as operator in Wild Basin at Mirada's election and that Mirada be allowed to elect a new operator; certain agreements apply to Oasis Petroleum and Mirada and Wild Basin with respect to this dispute; Oasis Petroleum be required to provide all information within its possession regarding proposed or ongoing operations in Wild Basin; and that OPNA not be permitted to drill, or propose to drill, more than one well at a time in Wild Basin without obtaining Mirada's consent. Mirada also seeks a declaratory judgment with respect to Oasis Petroleum's current midstream operations in Wild Basin. Specifically, Mirada seeks a declaratory judgment that Mirada has a right to participate in Oasis Petroleum's Wild Basin midstream operations, consisting of produced and flowback water disposal, crude oil gathering and natural gas gathering and processing; that, upon Mirada's election to participate, Mirada is obligated to pay its proportionate costs of Oasis Petroleum's midstream operations in Wild Basin; and that Mirada would then be entitled to receive a share of revenues from the midstream operations and would not be charged any amount for its use of these facilities for production from the "Contract Area."

On June 30, 2017, Mirada amended its original petition to add a claim that Oasis Petroleum has breached certain agreements by charging Mirada for midstream services provided by its affiliates and to seek a declaratory judgment that Mirada is entitled to be paid its share of total proceeds from the sale of hydrocarbons received by OPNA or any affiliate of OPNA without deductions for midstream services provided by OPNA or its affiliates.

On February 2, 2018 and February 16, 2018, Mirada filed a second and third amended petition, respectively. In these filings, Mirada alleged new legal theories for being entitled to enforce the underlying contracts and added Bighorn DevCo, Bobcat DevCo and Beartooth DevCo as defendants, asserting that these entities were created in bad faith in an effort to avoid contractual obligations owed to Mirada.

On March 2, 2018, Mirada filed a fourth amended petition that described Mirada's alleged ownership and assignment of interests in assets purportedly governed by agreements at issue in the lawsuit. On August 31, 2018, Mirada filed a fifth amended petition that added the Partnership as a defendant, asserting that it was created in bad faith in an effort to avoid contractual obligations owed to Mirada.

On July 2, 2019, Oasis Petroleum, OPNA, OMS, the Partnership, Bighorn DevCo, Bobcat DevCo and Beartooth DevCo (collectively "Oasis Entities") counterclaimed against Mirada for a judgment declaring that Oasis Entities are not obligated to purchase, manage, gather, transport, compress, process, market, sell or otherwise handle Mirada's proportionate share of oil and gas produced from OPNA-operated wells. The counterclaim also seeks attorney's fees, costs and expenses.

On November 1, 2019, Mirada filed a sixth amended petition that stated that Mirada seeks in excess of $200 million in damages and asserted that OMS is an agent of OPNA and OPNA, OMS, the Partnership, Bighorn DevCo, Bobcat DevCo and Beartooth DevCo are agents of Oasis Petroleum. Mirada also changed its allegation that it may elect a new operator for the subject wells to instead allege that Mirada may remove Oasis Petroleum as operator.

On November 1, 2019, the Oasis Entities amended their counterclaim against Mirada for a judgment declaring that a provision in one of the agreements does not incorporate by reference any provisions in a certain participation agreement and joint operating agreement. The additional counterclaim also seeks attorney's fees, costs and expenses. On the same day, the Oasis Entities filed an amended answer asserting additional defenses against Mirada's claims.

Oasis Petroleum and the Partnership believe that Mirada's claims are without merit, that Oasis Petroleum has complied with its obligations under the applicable agreements and that some of Mirada's claims are grounded in agreements which do not apply to Oasis Petroleum. Oasis Petroleum filed answers denying all of Mirada's claims and intends and continues to vigorously defend against Mirada's claims. Discovery is ongoing, and each of the parties has made a number of procedural filings and motions, and additional filings and motions can be expected over the course of the claim. Trial is scheduled for May 2020. Neither the Partnership nor Oasis Petroleum can predict or guarantee the ultimate outcome or resolution of such matter. If such matter were to be determined adversely to the Partnership's or Oasis Petroleum's interests, or if the Partnership or Oasis Petroleum were forced to settle such matter for a significant amount, such resolution or settlement could have a material adverse effect on the Partnership's business, financial condition, results of operations and cash flows. Such an adverse determination could materially impact Oasis Petroleum's ability to operate its properties in Wild Basin or develop its identified drilling locations in Wild Basin on its current development schedule. A determination that Mirada has a right to participate in Oasis Petroleum's midstream operations could materially reduce the interests of Oasis Petroleum and the Partnership in the Partnership's current assets and future midstream opportunities and related revenues in Wild Basin. Under the Omnibus Agreement the Partnership entered into with Oasis Petroleum in connection with the closing of the initial public offering, Oasis Petroleum agreed to indemnify the Partnership for any losses resulting from this litigation. However, the Partnership cannot guarantee that such indemnity will fully protect the Partnership from the adverse consequences of any adverse ruling.

In our midstream infrastructure business, we may not be able to attract additional third-party gathering volumes, which could limit our ability to grow and diversify our customer base.

Part of our long-term growth strategy includes identifying additional opportunities to offer services to third parties. Our ability to increase throughput on our midstream systems and any related revenue from third parties is subject to numerous factors beyond our control, including competition from third parties and the extent to which we have available capacity when requested by third parties. To the extent that we lack available capacity on our systems for third-party volumes or wells, we may not be able to compete effectively with third-party systems for additional volumes in our areas of operation.

Our efforts to attract new unaffiliated customers may be adversely affected by (i) our relationship with Oasis Petroleum and the fact that a substantial majority of the capacity of our midstream systems will be necessary to service Oasis Petroleum's production and development and completion schedule and (ii) our desire to provide our gathering activities pursuant to fee-based contracts. As a result, we may not have the capacity to provide midstream infrastructure services to third parties and/or potential third-party customers may prefer to obtain midstream infrastructure services pursuant to other forms of contractual arrangements under which we would be required to assume direct commodity exposure.

The continued growth of our business will be affected by the willingness of potential third-party customers to outsource their midstream infrastructure services needs generally, and to us specifically rather than to our competitors. Potential third-party customers who are significant producers of crude oil and natural gas may develop their own midstream systems in lieu of using our systems. Currently, many E&P companies own and operate waste treatment, recovery and disposal facilities. In addition, most crude oilfield operators have numerous abandoned wells that could be licensed for use in the disposition of internally generated produced and flowback water and third-party produced and flowback water in competition with us. Potential third-party customers could decide to process and dispose of their produced and flowback water internally or develop their own midstream infrastructure systems for produced and flowback water gathering and freshwater distribution, which could negatively impact our financial position, results of operations, cash flows and ability to make cash distributions to our unitholders.

We also have many competitors in the midstream infrastructure business. Other companies offer similar third-party natural gas gathering, compression, processing and gas lift; crude oil gathering, stabilization, blending, storage and transportation; produced and flowback water gathering and disposal; and freshwater distribution services in our areas of operation. Some of our competitors for third-party volumes have greater financial resources and access to larger supplies of crude oil and natural gas than those available to us, which could allow those competitors to price their services more aggressively than we do. With respect to our produced and flowback water gathering and disposal and freshwater distribution operations, vehicle-based competition has the ability to expand to additional basins more quickly than pipeline-based assets and at a lower initial capital cost. In addition, many companies manage a portion of their own produced and flowback water internally without using a third-party provider, and some companies also compete with us by offering gathering and disposal to other crude oil and natural gas companies. Furthermore, technologies may be developed that could be used by our customers to recycle produced and flowback water and to recover crude oil through crude oilfield waste processing. Potential third-party customers regularly evaluate the best combination of value and price from competing alternatives and new technologies and, in the absence of a long-term contractual arrangement, can move between alternatives or, in some cases, develop their own alternatives with relative ease. This competition influences the prices we charge and requires us to control our costs aggressively and maximize efficiency in order to maintain acceptable operating margins; however, we may be unable to do so and remain competitive on a cost-for-service basis. In addition, existing and future competitors may develop or offer midstream infrastructure or new technologies that have pricing, location or other advantages over the gathering and disposal services we provide, including a lower cost of capital.

If we are unable to make acquisitions on economically acceptable terms from Oasis Petroleum, any Oasis Petroleum successor or third parties, our future growth will be limited, and the acquisitions we do make may reduce, rather than increase, our distributable cash on a per unit basis.

Our ability to grow depends, in part, on our ability to make acquisitions that increase our distributable cash on a per unit basis. The acquisition component of our strategy is based, in large part, on our expectation of ongoing divestitures of assets by industry participants, including Oasis Petroleum. Though our Omnibus Agreement with Oasis Petroleum will provide us with a ROFO or ROFR, as applicable, with respect to the Subject Assets, there is no guarantee that we will be able to make any such offer or consummate any acquisition of assets from Oasis Petroleum or any Oasis Petroleum successor. A material decrease in divestitures of assets from Oasis Petroleum or any Oasis Petroleum successor would limit our opportunities for future acquisitions and could have a material adverse effect on our business, results of operations, financial condition and ability to make quarterly cash distributions to our unitholders.

If we are unable to make accretive acquisitions from Oasis Petroleum, any Oasis Petroleum successor or third parties, whether because, among other reasons, (i) Oasis Petroleum or any Oasis Petroleum successor elects not to sell or contribute additional assets to us, (ii) we are unable to identify attractive third-party acquisition opportunities, (iii) we are unable to negotiate acceptable purchase contracts with Oasis Petroleum, any Oasis Petroleum successor or third parties, (iv) we are unable to obtain financing for these acquisitions on economically acceptable terms, (v) we are outbid by competitors or (vi) we are unable to obtain necessary governmental or third-party consents, then our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in our distributable cash on a per unit basis.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, revenue and costs, including synergies and potential growth;
- an inability to secure adequate customer commitments to use the acquired systems or facilities;
- an inability to integrate successfully the assets or businesses we acquire;
- the assumption of unknown environmental and other liabilities for which we are not indemnified or for which our indemnity is inadequate;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- customer or key personnel losses at the acquired businesses;
- the diversion of management’s and employees’ attention from other business concerns; and
- unforeseen difficulties operating in new geographic areas or business lines.

If we are unable to make acquisitions from Oasis Petroleum or third parties, our future growth and ability to increase distributions will be limited. Furthermore, if any acquisition eventually proves not to be accretive to our distributable cash on a per unit basis, it could have a material adverse effect on our business, results of operations, financial condition and ability to make quarterly cash distributions to our unitholders.

Our ability to grow in the future is dependent on our ability to access external financing for expansion capital expenditures.

We will distribute all of our available cash after expenses to our unitholders. We expect that we will rely upon external financing sources, including borrowings under our revolving credit facility (as defined below) and the issuance of equity and debt securities, to fund expansion capital expenditures. However, we may not be able to obtain equity or debt financing on terms favorable to us, or at all. To the extent we are unable to efficiently finance growth externally, our cash distribution policy will significantly impair our ability to grow. In addition, because we distribute all of our available cash, we may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations. Furthermore, Oasis Petroleum is under no obligation to fund our growth. To the extent we issue additional units in connection with the financing of other expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of borrowings or other debt by us to finance our growth strategy would result in interest expense, which in turn would affect the available cash that we have to distribute to our unitholders.

Increased competition from other companies that provide midstream infrastructure could have a negative impact on the demand for our services, which could adversely affect our financial results.

Our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors. Our midstream infrastructure assets compete primarily with other midstream infrastructure assets. Some of our competitors have greater financial resources and may now, or in the future, have access to greater supplies of crude oil, natural gas and/or produced and flowback water than we do or have greater capacity for crude oil and natural gas gathering, produced and flowback water gathering and disposal and freshwater distribution than we do. Some of these competitors may expand or construct assets that would create additional competition for the services we provide to our customers. In addition, our customers may develop their own midstream assets instead of using ours. Moreover, Oasis Petroleum and its affiliates are not limited in their ability to compete with us.

All of these competitive pressures could make it more difficult for us to retain our existing customers and/or attract new customers as we seek to expand our business, which could have a material adverse effect on our business, financial condition, results of operations, cash flows and ability to make quarterly cash distributions to our unitholders. In addition, competition could intensify the negative impact of factors that decrease demand for crude oil and natural gas in the markets served by our assets, such as adverse economic conditions, weather, higher fuel costs and taxes or other governmental or regulatory actions that directly or indirectly increase the cost or limit the use of crude oil and natural gas.

We will be required to make substantial capital expenditures to increase our asset base. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to make cash distributions may be diminished or our financial leverage could increase.

In order to increase our asset base, we will need to make expansion capital expenditures. If we do not make sufficient or effective expansion capital expenditures, we will be unable to expand our business operations and, as a result, we will be unable to raise the level of our future cash distributions. To fund our expansion capital expenditures and investment capital expenditures, we will be required to use cash from our operations or incur borrowings. Such uses of cash from our operations will reduce our distributable cash. Alternatively, we may sell additional common units or other securities to fund our capital expenditures.

Our ability to obtain bank financing or to access the capital markets for future equity or debt offerings may be limited by our or Oasis Petroleum's financial condition at the time of any such financing or offering and the covenants in our existing debt agreements, as well as by general economic conditions, contingencies and uncertainties that are beyond our control. Even if we are successful in obtaining the necessary funds, the terms of such financings could limit our ability to pay distributions to our unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional limited partner interests may result in significant unitholder dilution and would increase the aggregate amount of cash required to maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the prevailing distribution rate. None of our General Partner, Oasis Petroleum or any of their respective affiliates is committed to providing any direct or indirect support to fund our growth outside of our contractual commercial agreements with Oasis Petroleum.

The amount of capital expenditures that we make over time could increase as a result of increased demand for labor and materials.

A substantial majority of our capital expenditures in the near term are expected to be incurred as a result of the continued build-out of our assets. As such, the amount of capital expenditures that we incur over time will be impacted by the cost of labor and materials needed to construct our pipelines. Additionally, any delays in construction as a result of weather-related events or otherwise could increase our overall capital expenditure requirements.

Oasis Petroleum may suspend, reduce or terminate its obligations under our natural gas gathering, compression, processing and gas lift; crude oil gathering, stabilization, blending, storage and transportation; produced and flowback water gathering and disposal; and freshwater distribution agreements in certain circumstances, which could have a material adverse effect on our financial condition, results of operations, cash flows and ability to make distributions to our unitholders.

Our natural gas gathering, compression, processing and gas lift; crude oil gathering, stabilization, blending, storage and transportation; produced and flowback water gathering and disposal; and freshwater distribution agreements with Oasis Petroleum include provisions that permit Oasis Petroleum to suspend, reduce or terminate its obligations under each agreement if certain events occur. These events include force majeure events that would prevent us from performing some or all of the required services under the applicable agreement. Oasis Petroleum has the discretion to make such decisions notwithstanding the fact that they may significantly and adversely affect us. Any such reduction, suspension or termination of Oasis Petroleum's obligations would have a material adverse effect on our financial condition, results of operations, cash flows and ability to make distributions to our unitholders.

The amount of our distributable cash depends primarily on our cash flows and not solely on profitability, which may prevent us from making distributions, even during periods in which we record net income.

The amount of our distributable cash 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 during periods when we record a net loss for financial accounting purposes, and conversely, we might fail to make cash distributions during periods when we record net income for financial accounting purposes.

Our utilization of existing capacity, expansion of existing midstream infrastructure assets and construction or purchase of new assets may not result in revenue increases and may be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our cash flows, results of operations and financial condition and, as a result, our ability to distribute cash to our unitholders.

The construction of additions or modifications to our existing systems and the construction or purchase of new assets involves numerous regulatory, environmental, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. Financing may not be available on economically acceptable terms 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 the imposition of tariffs. If we undertake these projects, we may not be able to complete them on schedule, at the budgeted cost or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For example, we may construct facilities to capture anticipated future production growth in an area in which such growth does not materialize, or if we build a new facility the construction may occur over an extended period of time, and we may not receive any material increases in revenues until the project is completed. As a result, new gathering, disposal or other assets 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 prior to constructing new pipelines or facilities. We may be unable to timely obtain such rights-of-way to connect new supplies to our existing gathering pipelines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to expand or renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, our cash flows could be adversely affected.

Our business would be adversely affected if we, Oasis Petroleum or our third-party customers experienced significant interruptions.

We depend upon the uninterrupted operations of our gathering system for the gathering of crude oil, natural gas and produced and flowback water, the disposal of produced and flowback water and the distribution of freshwater, as well as the need for collection of crude oil, natural gas and produced and flowback water produced by our customers, including Oasis Petroleum and third parties. Any significant interruption at these assets or facilities would adversely affect our results of operations, cash flows and ability to make distributions to our unitholders. Operations at our midstream infrastructure assets and at the facilities owned or operated by our customers whom we rely upon for producing crude oil, natural gas and produced and flowback water could be partially or completely shut down, temporarily or permanently, as the result of any number of circumstances that are not within our control, such as:

- catastrophic events, including tornadoes, seismic activity such as earthquakes, lightning strikes, fires and floods;
- loss of electricity or power;
- rupture, spills or other unauthorized releases in or from gathering pipelines and disposal facilities;
- explosion, breakage, loss of power or accidents to machinery, storage tanks or facilities;
- leaks in packers and tubing below the surface, failures in cement or casing or ruptures in the pipes, valves, fittings, hoses, pumps, tanks, containment systems or houses that lead to spills or employee injuries;
- environmental remediation;
- pressure issues that limit or restrict our ability to inject water into the disposal well or limitations with the injection zone formation and its permeability or porosity that could limit or prevent disposal of additional fluids;
- labor difficulties;
- malfunctions in automated control systems at our assets or facilities;
- disruptions in the supply of produced and flowback water to our assets;
- failure of third-party pipelines, pumps, equipment or machinery; and
- governmental mandates, compliance, inspection, restrictions or laws and regulations.

In addition, there can be no assurance that we are adequately insured against such risks. As a result, our revenue and results of operations could be materially adversely affected.

If third-party pipelines or other facilities interconnected to our midstream systems become partially or fully unavailable, or if the volumes we gather or treat do not meet the quality specifications of such pipelines or facilities, our business, financial condition, results of operations, cash flows and ability to make distributions to our unitholders could be adversely affected.

Our midstream systems are connected to other pipelines or facilities, some of which are owned by third parties. The continuing operation of such pipelines or facilities is not within our control. In addition, these downstream operators may impose specifications for the products that they are willing to accept. If the total mix of a product fails to meet the applicable product quality specifications, these downstream operators may refuse to accept all or a part of the products or may invoice us for the costs to handle or damages from receiving out-of-specification products.

If any of these pipelines or facilities becomes unable to gather, transport, treat or process natural gas or crude oil, or if the volumes we gather or transport do not meet the quality specifications of such pipelines or facilities, our business, financial condition, results of operations, cash flows and ability to make distributions to our unitholders could be adversely affected.

Our exposure to commodity price risk may change over time and we cannot guarantee the terms of any existing or future agreements for our midstream services with third parties or with Oasis Petroleum.

We currently generate the majority of our revenues pursuant to fee-based agreements under which we are paid based on volumetric fees, rather than the underlying value of the commodity. Consequently, our existing operations and cash flows have minimal direct exposure to commodity price risk. However, Oasis Petroleum and our other upstream customers are exposed to commodity price risk, and extended reduction in commodity prices could reduce the future production volumes available for our midstream services below expected levels. Although we intend to maintain fee-based pricing terms on both new contracts and existing contracts for which prices have not yet been set, our efforts to negotiate such terms may not be successful, which could have a materially adverse effect on our business.

Restrictions in our Revolving Credit Facility could adversely affect our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

Our revolving credit facility (the “Revolving Credit Facility”) contains a number of restrictive covenants that impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- incur or guarantee additional debt;
- redeem or repurchase units or make distributions under certain circumstances;
- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
- merge or consolidate with another company; and
- transfer, sell or otherwise dispose of assets.

Our Revolving Credit Facility also contains covenants requiring us to maintain certain financial ratios and tests. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure unitholders that we will meet any such ratios and tests.

The provisions of our Revolving Credit Facility may affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our Revolving Credit Facility could result in a default or an event of default that could enable our lenders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of our debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment. Please read “Part II. Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources.”

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

Our future level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures (including required well pad connections and well connections pursuant to our produced and flowback water gathering and disposal agreement as well as 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, investments or capital expenditures, selling assets or issuing equity. We may not be able to affect any of these actions on satisfactory terms or at all.

Increases in interest rates could adversely affect our business, our unit price and our ability to issue additional equity, to incur debt to capture growth opportunities or for other purposes, or to make cash distributions at our intended levels.

As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related 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 and our ability to issue additional equity, to incur debt to expand or for other purposes, or to make cash distributions at our intended levels.

Our business could be adversely impacted if we are unable to obtain or maintain the regulatory permits required to develop and operate our facilities or to dispose of certain types of wastes.

We own and operate crude oil gathering and transportation lines, natural gas gathering lines, a natural gas processing facility and produced and flowback water gathering and disposal facilities in North Dakota and Montana. Each state has its own regulatory program for addressing the gathering, transporting, processing, handling, treatment, recycling or disposal of crude oil, natural gas and produced and flowback water, as applicable. We are also required to comply with federal laws and regulations governing our operations. These environmental and other laws and regulations require that, among other things, we obtain permits and authorizations prior to the development and operation of crude oil and natural gas gathering or transportation lines, natural gas processing facilities, waste treatment and storage facilities and in connection with the disposal and transportation of certain types of wastes. The applicable regulatory agencies strictly monitor waste handling and disposal practices at our facilities. For many of our sites, we are required under applicable laws, regulations and/or permits to conduct periodic monitoring, company-directed testing and third-party testing. Any failure to comply with such laws, regulations or permits may result in suspension or revocation of necessary permits and authorizations, civil or criminal liability and imposition of fines and penalties, which could adversely impact our operations and revenues and ability to continue to provide crude oil and natural gas gathering and transportation, natural gas processing and crude oilfield water services to our E&P customers.

In addition, we may experience a delay in obtaining, be unable to obtain, or suffer the revocation of required permits or regulatory authorizations, which may cause us to be unable to serve customers, interrupt our operations and limit our growth and revenue. Regulatory agencies may impose more stringent or burdensome restrictions or obligations on our operations when we seek to renew or amend our permits. For example, permit conditions may limit the amount or types of wastes we may accept, require us to make material expenditures to upgrade our facilities, implement more burdensome and expensive monitoring or sampling programs, or increase the amount of financial assurance that we provide to cover future facility closure costs. Moreover, shareholder activists, non-governmental organizations or the public may elect to protest the issuance or renewal of our permits on the basis of developmental, environmental or aesthetic considerations, which protests may contribute to a delay or denial in the issuance or reissuance of such permits.

Delays in obtaining permits by our crude oil and natural gas E&P customers for their operations could impair our business.

In most states, our E&P customers are required to obtain permits from one or more governmental agencies in order to perform drilling and completion activities and to operate certain types of crude oilfield facilities. As with all governmental permitting processes, there is a degree of uncertainty as to whether a permit will be granted, the time it will take for a permit to be issued, and the conditions that may be imposed in connection with the granting of the permit. Some of our customers' drilling and completion activities may take place on federal land or Native American lands, requiring leases and other approvals from the federal government or Native American tribes to conduct such drilling and completion activities. In some cases, federal agencies have cancelled proposed leases for federal lands and refused or delayed required approvals. Consequently, our customers' operations in certain areas of the United States may be interrupted or suspended for varying lengths of time, resulting in reduced demand for our gathering, transportation, processing and/or disposal services and a corresponding loss of revenue to us as well as adversely affecting our results of operations in support of those customers.

In the future we may face increased obligations relating to the closing of our produced and flowback water facilities and may be required to provide an increased level of financial assurance to guaranty the appropriate closure activities occur for a produced and flowback water facility.

Obtaining a permit to own or operate produced and flowback water facilities generally requires us to establish performance bonds, letters of credit or other forms of financial assurance to address clean-up and closure obligations. As we acquire additional produced and flowback water facilities or expand our existing produced and flowback water facilities, these obligations will increase. Additionally, in the future, regulatory agencies may require us to increase the amount of our closure bonds at existing produced and flowback water facilities. We have accrued $1.7 million on our consolidated balance sheet related to our future closure obligations of our produced and flowback water facilities as of December 31, 2019. However, actual costs could exceed our current expectations, as a result of, among other things, federal, state or local government regulatory action, increased costs charged by service providers that assist in closing produced and flowback water facilities and additional environmental remediation requirements. The obligation to satisfy increased regulatory requirements associated with our produced and flowback water facilities could result in an increase of our operating costs and cause our available cash that we have to distribute to our unitholders to decline.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs of doing business and additional operations restrictions for our crude oil and natural gas E&P customers, which could reduce the throughput on our midstream infrastructure assets and adversely impact our revenues.

Hydraulic fracturing is an important and common well stimulation process that utilizes large volumes of water and sand, or other proppant, combined with fracturing chemical additives that are pumped at high pressure to crack open dense subsurface rock formations to release hydrocarbons. Our E&P customers—primarily Oasis Petroleum—regularly conduct hydraulic fracturing operations. Substantially all of Oasis Petroleum's crude oil and natural gas production is being developed from shale formations. These reservoirs require hydraulic fracturing completion processes to release the crude oil and natural gas from the rock so that it can flow through casing to the surface. Hydraulic fracturing is currently generally exempt from regulation under the SDWA UIC program. In recent years, however, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing.

Hydraulic fracturing is typically regulated by state crude oil and natural gas commissions or similar agencies. However, federal regulatory agencies have conducted investigations regarding, or asserted regulatory authority over, certain aspects of the process. 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 some circumstances. Additionally, the EPA has asserted regulatory authority pursuant to the SDWA over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities; the EPA has issued an Advance Notice of Proposed Rulemaking under Section 8 of the Toxic Substances Control Act to require reporting of the chemical substances and mixtures used in hydraulic fracturing; and published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional crude oil and natural gas extraction facilities to publicly owned wastewater treatment plants. From time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing, including the underground disposal of fluids or propping agents associated with such fracturing activities and the disclosure of the chemicals used in the fracturing process. However, concern over the threat of climate change has resulted in certain candidates seeking the office of the President of the United States in 2020 to make pledges to ban hydraulic fracturing of oil and natural gas wells.

In addition, a number of states, including North Dakota, Montana and Texas, where we operate, have adopted, and other states are considering adopting regulations that impose new or more stringent permitting, disclosure, disposal and well construction requirements on hydraulic fracturing operations. States could elect to place prohibitions on hydraulic fracturing, following the approach taken by the States of Maryland, New York and Vermont. Also, local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular.

If new federal, state or local restrictions or bans on hydraulic fracturing are adopted in areas where our E&P customers operate, Oasis Petroleum and our other third-party E&P producing customers' fracturing activities could become subject to additional permit requirements, reporting requirements or operational restrictions and associated permitting delays, restrictions or cancellations in their production activities or additional costs that could adversely affect the determination of whether a well is commercially viable. Restrictions or bans on hydraulic fracturing could also reduce the amount of crude oil and natural gas that our customers are ultimately able to produce in commercial quantities. A reduction in production of crude oil and natural gas would likely reduce the demand for our gathering, transporting, processing and disposal services, which adversely impacts our revenues and profitability. Therefore, if these expenditures decline, our business is likely to be adversely affected.

Legislation or regulatory initiatives intended to address seismic activity could restrict our ability to dispose of produced and flowback water gathered from Oasis Petroleum and our other third-party E&P customers, which could have a material adverse effect on our business.

We dispose of large volumes of produced and flowback water gathered from Oasis Petroleum and our other third-party E&P customers produced in connection with their drilling and production operations pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities.

For example, there exists a growing concern amongst the public and federal and state agencies that the injection of produced and flowback water into belowground disposal wells triggers seismic activity in certain areas, including North Dakota and Montana, where we operate. In response to these concerns, federal and some state agencies are investigating whether such wells have caused increased seismic activity. In 2016, the United States Geological Survey identified Texas as being among six states with areas of increased rates of induced seismicity that could be attributed to fluid injection or crude oil and natural gas extraction. Since that time, the United States Geological Survey indicates that these rates have decreased in these states, although concern continues to exist over quakes arising from induced seismic activities. Also, regulators in some states have adopted, and other states are considering adopting additional requirements related to seismic safety, including the permitting of disposal wells or otherwise to assess any relationship between seismicity and the use of such wells, which has resulted in some states restricting, suspending or shutting down the use of such injection wells. For example, in Texas, the Texas Railroad Commission has adopted rules governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of crude oil and natural gas in order to address these seismic activity concerns within the state. Also, North Dakota requires a map depicting the area around the location where the disposal well is proposed that depicts any known or suspected faults. The adoption and implementation of any new laws or regulations that restrict our ability to dispose of produced and flowback water gathered from Oasis Petroleum and our other third-party E&P customers, by limiting volumes, disposal rates, disposal well locations or otherwise, or requiring us to shut down disposal wells, could reduce the demand for our produced and flowback water gathering and disposal services and have a material adverse effect on our business, financial condition and results of operations.

Compliance with environmental laws and regulations could cause us and our E&P customers to incur significant costs or liabilities as well as delays in our E&P customers' production that could reduce our volume of services and have a material adverse effect on our business.

Our crude oil gathering and transportation, natural gas gathering and processing, and produced and flowback water gathering and disposal services as well as related crude oilfield operations are subject to stringent federal, tribal, state and local laws and regulations governing the handling, disposal and discharge of materials and wastes and the protection of natural resources and the environment. 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 response actions. These laws and regulations may impose numerous obligations that are applicable to our and our E&P customers' operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital or operating expenditures to limit or prevent releases of materials from our or our customers' operations, the prohibition of noise-producing activities, the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas and the imposition of substantial liabilities and remedial obligations for pollution or contamination resulting from our and our customers' operations. Compliance with environmental laws and regulations is difficult and may require us to make significant expenditures. Failure to comply with these laws, regulations and permits 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, denials, 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 a particular area. Private parties, including the owners of the properties through which our gathering line assets pass or our processing plant is located, properties we formerly operated, and facilities where wastes resulting from our operations are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance and require the cleanup of any contamination, as well as to seek damages for non-compliance with environmental laws, regulations and permits or for personal injury or property damage. We may not be able to recover all or any of these costs from insurance. We may also experience a delay in obtaining or be unable to obtain required permits, which may cause us to lose potential and current E&P customers, interrupt our operations and limit our growth and revenues, which in turn could affect our profitability. In addition, our customers' liability under, or costs and expenditures to comply with, environmental laws and regulations could lead to delays and increased operating costs, which could reduce the volumes of crude oil and natural gas that move through our gathering line assets or processing plant.

Our operations also pose risks of environmental liability due to spills or other releases from our operations to surface or subsurface soils, surface water or groundwater. Certain environmental laws impose strict as well as joint and several liability for costs required to remediate and restore sites where hydrocarbons, materials or wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In connection with certain acquisitions, we could assume, or be required to provide indemnification against, environmental liabilities that could expose us to material losses. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in material increases in our costs of doing business and consequently affecting profitability. For example, in 2015, the EPA issued a final rule under the CAA, lowering the NAAQS for ground-level ozone to 70 parts per billion under both the primary and secondary standards. Since that time, the EPA has issued area designations with respect to ground-level ozone and has issued final requirements that apply to state, local and tribal air agencies for implementing the 2015 NAAQS. State implementation of these revised standards for ground-level ozone could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant. In another example, the EPA and the Corps under the Obama Administration published a final rule in 2015 that attempted to clarify federal jurisdiction under the Clean Water Act over waters of the United States, including wetlands. In June 2017, the EPA and the Corps under the Trump Administration agreed to reconsider the 2015 rule and, thereafter, on October 22, 2019, the agencies published a final rule made effective on December 23, 2019, rescinding the 2015 rule. On January 23, 2020, the two agencies issued a final rule re-defining such jurisdiction, which redefinition is narrower than found in the 2015 rule. Upon being published in the Federal Register and the passage of 60 days thereafter, the January 23, 2020 final rule will become effective, at which point the United States will be covered under a single regulatory scheme as it relates to federal jurisdictional reach over waters of the United States. However, there remains the expectation that the January 23, 2020 final rule also will be legally challenged by those who oppose less stringent federal permitting authority in federal district court, following the rules publication in the Federal Register. To the extent that any challenge to the January 23, 2020 final rule is successful and the 2015 rule or a revised rule expands the scope of the Clean Water Act's jurisdiction in areas where we or our customers conduct operations, such developments could delay, restrict or halt the development of projects, result in longer permitting timelines, or increased compliance expenditures or mitigation costs for our and our oil and natural gas customers' operations, which may reduce the rate of production of natural gas or crude oil from operators with whom we have a business relationship and, in turn, have a material adverse effect on our business, results of operations and cash flows.

Changes in environmental laws and regulations occur frequently, and compliance with more stringent requirements may increase the costs to our E&P customers of developing and producing petroleum hydrocarbons, which could lead to reduced operations by these customers and, as a result, may have an indirect and adverse effect on the amount of customer-produced crude oil or natural gas gathered, transported or processed by us or produced and flowback water delivered to our facilities by our customers, which could have a material adverse effect on our financial condition and results of operations.

Our and our E&P customers' operations are subject to a number of risks arising out of the threat of climate change that could result in increased operating costs and costs of compliance, limit the areas in which crude oil and natural gas production may occur and reduce demand for the crude oil and natural gas that we handle, while potential physical effects of climate change could disrupt our operations and cause us to incur significant costs in preparing for or responding to those effects.

The threat of climate change continues to attract considerable attention in the United States and in foreign countries. As a result, our operations as well as the operations of our E&P customers are subject to a number of regulatory, political, litigation and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, with the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, the EPA has adopted rules that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources, implement New Source Performance Standards ("NSPS") directing the reduction of methane from certain new, modified or reconstructed facilities in the crude oil and natural gas sector, and together with the U.S. Department of Transportation, implement GHG emissions limits on vehicles manufactured for operation in the United States. Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there exists the United Nations-sponsored "Paris Agreement," which is a non-binding agreement for nations to limit their GHG emissions through individually-determined reduction goals every five years after 2020, although the United States has announced its withdrawal from such agreement, effective November 4, 2020.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions has resulted in federal political risks in the United States in the form of pledges made by certain candidates seeking the office of the President of the United States in 2020. Critical declarations made by one or more presidential candidates include proposals to ban hydraulic fracturing of crude oil and natural gas wells and ban new leases for production of minerals on federal properties, including onshore lands and offshore waters. Other actions to crude oil and natural gas production activities that could be pursued by presidential candidates may include more restrictive requirements for the establishment of pipeline infrastructure or the permitting of liquified natural gas export facilities, as well as the rescission of the United States' withdrawal from the Paris Agreement in November 2020. Litigation risks are also increasing, as a number of cities, local governments and other plaintiffs have sought to bring suit against the largest crude oil and natural gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as shareholders and bondholders currently invested in fossil-fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, the lending practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the international Paris Agreement, and foreign citizenry concerned about climate change not to provide funding for fossil fuel producers. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs, development activities or production activities.

The adoption and implementation of any international, federal or state legislation, regulations or other regulatory initiatives that require reporting of GHGs or otherwise restricts emissions of GHGs from our or our E&P customers' equipment and operations could require us and our customers to incur increased costs, adversely affect demand for the crude oil and natural gas we handle or produced and flowback water we gather and dispose of and thus have a material adverse effect on our business, financial condition and results of operations.

Additionally, political, financial and litigation risks may result in us and our customers restricting or canceling production activities, incurring liability for infrastructure damages, environmental damages or personal injury damages as a result of climatic changes or impairing the ability to continue to operate in an economic manner, which also could reduce demand for our midstream services. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation. Finally, it should be noted that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If such effects were to occur, they could have an adverse effect on our operations. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations.

The rates of our regulated assets are subject to review and reporting by federal regulators, which could adversely affect our revenues.

Currently, only the crude oil transportation system connecting the Wild Basin area to the Johnson's Corner market center transports crude oil in interstate commerce. Pipelines that transport crude oil in interstate commerce are, among other things, subject to rate regulation by FERC, unless such rate requirements are waived. FERC regulates interstate transportation of crude oil under the ICA, the Energy Policy Act of 1992 and the rules and regulations promulgated under those laws. FERC regulations require that rates and terms and conditions of service for interstate service pipelines that transport crude oil be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. FERC's regulations also require interstate pipelines to file with FERC and publicly post tariffs stating their interstate transportation rates and terms and conditions of service.

Under the ICA, FERC or interested persons may challenge existing or proposed new or changed rates, services, or terms and conditions of service. Under certain circumstances, FERC could limit a regulated pipeline's ability to charge rates until completion of an investigation during which FERC could find that the new or changed rate is unlawful. In contrast, FERC has clarified that initial rates and terms of service agreed upon with committed shippers in a transportation services agreement are not subject to protest or a cost-of-service analysis where the pipeline held an open season offering all potential shippers service on the same terms.

A successful rate challenge could result in a regulated pipeline paying refunds of revenue collected in excess of the just and reasonable rate, together with interest for the period that the rate was in effect, if any. FERC may also order a pipeline to reduce its rates prospectively, and may require a regulated pipeline to pay shippers reparations retroactively for rate overages for a period of up to two years prior to the filing of a complaint. FERC also has the authority to change terms and conditions of service if it determines that they are unjust or unreasonable or unduly discriminatory or preferential. We may also be required to respond to requests for information from government agencies, including compliance audits conducted by FERC.

FERC's ratemaking policies are subject to change and may impact the rates charged and revenues received from the operation of our crude oil gathering system in the Wild Basin area and any other natural gas or liquids pipeline that is determined to be under the jurisdiction of FERC. In 2005, FERC issued a policy statement stating that it would permit common carrier pipelines, among others, to include an income tax allowance in cost-of-service rates to reflect actual or potential tax liability attributable to a regulated entity's operating income, regardless of the form of ownership. On December 15, 2016, FERC issued a Notice of Inquiry requesting energy industry input on how FERC should address income tax allowances in cost-based rates proposed by pipeline companies organized as part of a master limited partnership. FERC's current policy permits pipelines and storage companies to include a tax allowance in the cost-of-service used as the basis for calculating their regulated rates. For pipelines and storage companies owned by partnerships or limited liability company interests, the current tax allowance policy reflects the actual or potential income tax liability on the FERC jurisdictional income attributable to all partnership or limited liability company interests if the ultimate owner of the interest has an actual or potential income tax liability on such income. FERC issued the Notice of Inquiry in response to a remand from the United States Court of Appeals for the D.C. Circuit 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 flows return on equity would not result in the pipeline partnership owners double-recovering their income taxes. We cannot predict whether FERC will successfully justify its conclusion that there is no double recovery of taxes under these circumstances or whether FERC will modify its current policy on either income tax allowances or return on equity calculations for pipeline companies organized as part of a master limited partnership. However, any modification that reduces or eliminates an income tax allowance for pipeline companies organized as a part of a master limited partnership or decreases the return on equity for such pipelines could result in an adverse impact on our revenues associated with the transportation services we provide pursuant to cost-based rates.

On December 22, 2017, the President signed into law Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act. The Tax Cuts and Jobs Act made significant changes to the U.S. federal income tax law, including a reduction in the maximum corporate tax rate. Following the enactment of the Tax Cuts and Jobs Act, filings have been made at FERC requesting that FERC require pipelines to lower their transportation rates to account for the reduction in the corporate tax rate. FERC may enact regulations or issue requests to pipelines regarding the impact of the corporate tax rate change on the rates. However, FERC’s establishment of a just and reasonable rate is based on many components, and the reduction in the corporate tax rate may only impact two of such components, the allowance for income taxes and the amount for accumulated deferred income taxes. Because our existing jurisdictional rates were established based on a higher corporate tax rate, FERC or our shippers may challenge these rates in the future, and the resulting new rate may be lower than the rates we currently charge.

Failure to comply with applicable market behavior rules, regulations and orders could subject us to substantial penalties and fines.

In August 2005, Congress enacted the EPAct 2005. Among other matters, the EPAct 2005 amended the NGA to add an anti-manipulation provision that makes it unlawful for “any entity” to engage in prohibited behavior in contravention of rules and regulations to be prescribed by FERC and, furthermore, provides FERC with additional civil penalty authority. In January 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provisions of the EPAct 2005. The rules make it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC or the purchase or sale of transportation services subject to the jurisdiction of FERC to (1) use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. Such anti-manipulation rules apply to interstate gas pipelines and storage companies and intrastate gas pipelines and storage companies that provide interstate services, such as NGPA Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC’s jurisdiction. The anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering to the extent such transactions do not have a “nexus” to jurisdictional transactions. The EPAct 2005 also amended the NGA and the NGPA to give FERC authority to impose civil penalties for violations of these statutes and FERC’s regulations, rules and orders, up to $1,000,000 per violation per day for violations occurring after August 8, 2005. In January 2018, FERC increased that maximum penalty to $1,291,894 per violation per day, adjusted annually for inflation. In connection with this enhanced civil penalty authority, FERC issued a revised policy statement on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. In addition, the Commodities Futures Trading Commission (the “CFTC”) is directed under the Commodities Exchange Act (the “CEA”) to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act and other authority, the CFTC has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of $1,212,866, adjusted annually for inflation or triple the monetary gain to the violator for violations of the anti-market manipulation sections of the CEA. Should we fail to comply with all applicable FERC, CFTC or other statutes, rules, regulations and orders governing market behavior, we could be subject to substantial penalties and fines.

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 may result in increased regulation of our assets, which may cause our operating expenses to increase, limit the rates we charge for certain services and decrease the amount of our distributable cash.

Although FERC has not made a formal determination with respect to the facilities we consider to be natural gas gathering pipelines, we believe that our natural gas gathering pipelines meet the traditional tests that FERC has used to determine that a pipeline is a gathering pipeline and is therefore not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and

FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities is subject to change based on future determinations by FERC, the courts or Congress. If FERC were to consider the status of an individual facility and determine that the facility or services provided by it are not exempt from FERC regulation under the NGA and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by FERC under the NGA or the NGPA. Such regulation could decrease revenue, increase operating costs and, depending upon the facility in question, adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of substantial civil penalties, as well as a requirement to disgorge revenues collected for such services in excess of the maximum rates established by FERC.

Our natural gas gathering pipelines are exempt from the jurisdiction of FERC under the NGA, but FERC regulation may indirectly impact gathering services. FERC's policies and practices across the range of its crude oil and natural gas regulatory activities, including, for example, its policies on interstate open access transportation, ratemaking, capacity release, and market center promotion, may indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate crude oil and natural gas pipelines. However, we cannot assure our unitholders that FERC will continue to pursue this approach as it considers matters such as pipeline rates and rules and policies that may indirectly affect our natural gas gathering services.

Natural gas gathering may receive greater regulatory scrutiny at the state level; therefore, our natural gas gathering operations could be adversely affected should they become subject to the application of state regulation of rates and services. Our gathering operations could also be subject to safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance of gathering facilities. We cannot predict what effect, if any, such changes might have on our operations, but we could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

In addition, certain of our crude oil gathering pipelines do not provide interstate services and therefore are not subject to regulation by FERC pursuant to the ICA. The distinction between FERC-regulated interstate pipeline transportation, on the one hand, and intrastate pipeline transportation, on the other hand, also is a fact-based determination. The classification and regulation of these crude oil gathering pipelines are subject to change based on future determinations by FERC, federal courts, Congress or by regulatory commissions, courts or legislatures in the states in which our crude oil gathering pipelines are located. We cannot provide assurance that FERC will not in the future, either at the request of other entities or on its own initiative, determine that some or all of our gathering pipeline systems and the services we provide on those systems are within FERC's jurisdiction. If it was determined that more or all of our crude oil gathering pipeline systems are subject to FERC's jurisdiction under the ICA, and are not otherwise exempt from any applicable regulatory requirements, the imposition of possible cost-of service rates and common carrier requirements on those systems could adversely affect the results of our operations on those systems.

We must comply with occupational health and safety laws and regulations at our facilities and in connection with our operations and failure to do so could result in significant liability and/or fines and penalties.

We are subject to a wide range of national, state and local occupational health and safety laws and regulations that impose specific standards addressing worker health and safety matters. Regulations implementing these health and safety laws are adopted and enforced by the OSHA and analogous state agencies whose purpose is to protect the health and safety of workers. In addition, OSHA's implementation of the hazard communication standard, the EPA's implementation of the community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes and any implementing regulations require that we maintain, organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens. These legal requirements are subject to change, as are the enforcement priorities of OSHA and the analogous state agencies. Failure to comply with these health and safety laws and regulations could lead to third-party claims, criminal and regulatory violations, civil fines and changes in the way we operate our facilities, each of which could increase the cost of operating our business and have a material adverse effect on our financial position, results of operations and cash flows and our 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. The occurrence of a significant accident or other event that is not fully insured could curtail our operations and have a material adverse effect on our ability to distribute cash and, accordingly, the market price for our common units.

Our operations are subject to all of the hazards inherent in the lines of business we participate in, including:

- damages to pipelines, terminals and facilities, related equipment and surrounding properties caused by earthquakes, tornadoes, floods, fires, severe weather, explosions and other natural disasters and acts of terrorism or vandalism;

- maintenance, repairs, mechanical or structural failures at our or Oasis Petroleum's facilities or at third-party facilities on which our or Oasis Petroleum's operations are dependent, including electrical shortages, power disruptions and power grid failures;
- equipment defects, vehicle accidents, blowouts, surface cratering, uncontrollable flows of natural gas or well fluids, abnormally pressured formations and various environmental hazards such as unauthorized crude oil or produced water spills and releases of, and exposure to, hazardous substances;
- leaks of natural gas and other hydrocarbons or losses of natural gas as a result of the malfunction of equipment or facilities;
- leaks of natural gas containing hazardous quantities of hydrogen sulfide;
- risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives;
- damages to and loss of availability of interconnecting third-party pipelines, railroads, terminals and other means of delivering produced and flowback water, freshwater, crude oil and natural gas;
- crude oil tank car derailments, fires, explosions and spills;
- disruption or failure of information technology systems and network infrastructure due to various causes, including unauthorized access or attack;
- curtailments of operations due to severe seasonal weather;
- riots, strikes, lockouts or other industrial disturbances;
- governmental mandates, compliance, inspections restrictions or laws and regulations; and
- other hazards.

Any of these risks could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. Certain of our insurance policies also provide coverage to Oasis Petroleum and as a result, a claim by Oasis Petroleum against one of our shared insurance policies may reduce the remaining amount of coverage available to the Partnership. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls, substantial changes to existing integrity management programs or more stringent enforcement of applicable legal requirements could subject us to increased capital and operating costs and operational delays.

Certain of our pipelines are subject to regulation by PHMSA under the HLPSA with respect to crude oil and the NGPSA with respect to natural gas. The HLPSA and NGPSA govern the design, installation, testing, construction, operation, replacement and management of crude oil and natural gas pipeline facilities. These laws have resulted in the adoption of rules by PHMSA, that, among other things, require transportation pipeline operators to implement integrity management programs, including more frequent inspections, correction of identified anomalies and other measures to ensure pipeline safety in HCAs and MCAs. In addition, states have adopted regulations similar to existing PHMSA regulations for certain intrastate gas and hazardous liquid pipelines, which regulations may impose more stringent requirements than found under federal law. Historically, our pipeline safety 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 be material in the future or that such future compliance costs will not have a material adverse effect on our business and operating results. New laws or regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement 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.

Legislation 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 HLPSA and NGPSA have been amended by the 2011 Pipeline Safety Act and 2016 Pipeline Safety Act. The 2011 Pipeline Safety Act increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. The 2016 Pipeline Safety Act extended PHMSA's statutory mandate through September 2019 and, among other things, required PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and develop new safety standards for natural gas storage facilities. The 2016 Act also empowers PHMSA to address unsafe conditions and practice constituting imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of hazardous liquid or natural gas pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued an interim rule in 2016 and a final rule on October 1, 2019 to implement the agency's expanded authority to address such conditions or practices that pose an imminent hazard to life, property or the environment. Because the 2016 Pipeline Safety Act reauthorized PHMSA's hazardous liquid and gas pipeline programs only through September 30, 2019, we anticipate that Congress will issue an updated pipeline safety law in 2020 that will reauthorize those programs through 2023.

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, on October 1, 2019, PHMSA published 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 and expanded use of leak detection systems, regardless of the pipeline's proximity to an HCA (for example, integrity assessments at least once every 10 years for onshore, piggable, hazardous liquid pipeline segments located outside of HCAs, and expanded use of leak detection systems outside of HCAs on all regulated hazardous liquid pipelines other than offshore gathering and regulated rural gathering pipelines). The final rule was initially issued by PHMSA under the Obama Administration in late 2016 but publication and effectiveness of the final rule was subsequently delayed following the election of President Trump and change in presidential administrations in January 2017. The October 1, 2019 final rule becomes effective on July 1, 2020 and, in addition to the stated integrity management requirements, requires all hazardous liquid pipelines in or affecting an HCA to be capable of accommodating in-line inspection tools within the next 20 years unless the basic construction of a pipeline cannot be modified to permit that accommodation. Also, this final rule extends annual accident and safety-related conditional reporting requirements to hazardous liquid gravity lines and certain gathering lines and also imposes inspection requirements on hazardous liquid pipelines in areas affected by extreme weather events and natural disasters, such as hurricanes, landslides, floods, earthquakes or other similar events that are likely to damage infrastructure.

In a second example, in 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain natural gas lines and gathering lines including, among other things, expanding certain of PHMSA's current regulatory safety programs for natural gas pipelines in newly defined MCAs; 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 for natural gas pipelines and also require consideration of seismicity in evaluating threats to pipelines. PHMSA has since decided to split its proposed rule, now referred to as the "Gas Mega Rule," into three separate rulemaking proceedings to facilitate completion. The first of these three rulemakings, relating to onshore gas transmission pipelines, was published as a final rule on October 1, 2019, becomes effective on July 1, 2020, and imposes numerous requirements on such pipelines, including maximum allowable operating pressure reconfirmation, the assessment of additional pipeline mileage outside of HCAs (including all MCAs and those Class 3 and Class 4 areas not found in HCAs) within 14 years of the publication date and at least once every 10 years thereafter, the reporting of exceedances of maximum allowable operating pressures, and the consideration of seismicity as a risk factor in integrity management. The remaining rulemakings comprising the Gas Mega Rule are expected to be issued in 2020. New legislation or any new 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 the absence of the PHMSA pursuing any legal requirements, state agencies, to the extent authorized, may pursue state standards, including standards for rural gathering lines.

We do not own all of the land on which our facilities are located, which could result in disruptions to our operations.

We do not own all of the land on which our facilities have been constructed, and we are, therefore, subject to the possibility of more onerous terms 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 assets on land owned by third parties and governmental agencies for a specific period of time. Additionally, the federal Tenth Circuit Court of Appeals has held tribal ownership of even a very small fractional interest in an allotted land, that is, tribal land owned or at one time owned by an individual Indian landowner, bars condemnation of any interest in the allotment. Consequently, the inability to condemn such allotted lands under circumstances where an existing pipeline rights-of-way may soon lapse or terminate serves as an additional impediment for pipeline operators. 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 right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

A shortage of equipment and skilled labor could reduce equipment availability and labor productivity and increase labor and equipment costs, which could have a material adverse effect on our business and results of operations.

Midstream infrastructure assets require special equipment and laborers skilled in multiple disciplines, such as equipment operators, mechanics and engineers, among others. If we experience shortages of necessary equipment or skilled labor in the future, our labor and equipment costs and overall productivity could be materially and adversely affected. If our equipment or labor prices increase or if we experience materially increased health and benefit costs for employees, our results of operations could be materially and adversely affected.

The loss of key personnel could adversely affect our ability to operate.

We depend on the services of a relatively small group of our General Partner’s and Oasis Petroleum’s senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. Because competition for experienced personnel in the industry is intense, we may not be able to find acceptable replacements with comparable skills and experience. The loss of the services of our General Partner’s or Oasis Petroleum’s senior management or technical personnel could have a material adverse effect on our business, financial condition and results of operations.

We do not have any officers or employees apart from those seconded to us and rely solely on officers of our General Partner and employees of Oasis Petroleum pursuant to our Services and Secondment Agreement with Oasis Petroleum.

We are managed and operated by the board of directors of our General Partner. Affiliates of Oasis Petroleum conduct businesses and activities of their own in which we have no economic interest. As a result, there could be material competition for the time and effort of the officers and employees who provide services to our General Partner and Oasis Petroleum. If our General Partner and the officers and employees of Oasis Petroleum do not devote sufficient attention to the management and operation of our business, our financial results may suffer, and our ability to make distributions to our unitholders may be reduced.

Crude oil and natural gas producers’ operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water. Restrictions on the ability to obtain water may incentivize water recycling efforts by our customers, which would decrease the volume of non-hazardous waste and water delivered to our facilities and could have an adverse effect on our cash flows.

Water is an essential component of crude oil and natural gas production during both the drilling and hydraulic fracturing processes. However, the availability of suitable water supplies may be limited by prolonged drought conditions and changing laws and regulations relating to water use and conservation. For example, in North Dakota, the Missouri River has been a preferred source for water used in hydraulic fracturing operations occurring in the state. However, in recent years, the Corps has restricted access to the Missouri River within certain reservoirs along Lake Sakakawea and Lake Oahe. In 2010, the Corps placed a moratorium on issuing new real estate permits, which in turn blocked any new industrial water intakes, around Lake Sakakawea. In 2013, the Corps lifted the moratorium, but the issuance of water easements and access may continue to be restricted by the Corps. Drought conditions, in conjunction with restricted access to waters of the Missouri River by the Corps, may result in increased operating costs, as industrial water users may be required to haul available water over longer distances. The occurrence of any one or more of these developments may result in reduced operations by our crude oil and natural gas producing customers, which could result in decreased volumes of return flow water being delivered to our facilities.

Our E&P customers must comply with North Dakota rules on the capture rather than flaring of natural gas in connection with production of crude oil and natural gas, which compliance activities may increase the costs of compliance and restrict or prohibit future production, which results could adversely affect our services.

In 2014, the NDIC adopted the 2014 Order, pursuant to which the agency adopted legally enforceable “gas capture percentage goals” targeting the capture of natural gas produced in the state between October 1, 2014 and October 1, 2020. Modification of the 2014 Order by the NDIC in late 2015 resulted in revised gas capture percentage goals of 88% and 91% required to be achieved by November 1, 2018 and November 1, 2020, respectively. Recently, in November 2018, the NDIC considered revising its 2018 and 2020 gas capture percentage goals but elected to retain those standards; however, the NDIC revised the flaring program’s policy goals such that the crude oil and gas exploration and production industry has more flexibility in removing certain gas volumes from consideration in calculating compliance with the state’s gas capture percentage goals. The NDIC continues to adhere to other aspects of the modified 2014 Order, including development of Gas Capture Plans that provide measures for reducing the amount of natural gas flared by those operators so as to be consistent with the agency’s gas capture percentage goals. Also, wells must continue to meet or exceed the NDIC’s gas capture percentage goals on a per-well, per-field, county or statewide basis. If an operator is unable to attain the applicable gas capture percentage goal at maximum efficient rate, wells will be restricted in production to 200 barrels of crude oil per day if at least 60% of the monthly volume of associated natural gas produced from the well is captured, or otherwise crude oil production from such wells shall not exceed 100 barrels of crude oil per day. However, the NDIC will consider flexibility to these production restrictions, by means of temporary exemptions, for other types of extenuating circumstances after notice and hearing if the effect of such flexibility is a significant net increase in gas capture within one year of the date such relief is granted. Monetary penalty provisions also apply under this policy in the event an operator not meeting the gas capture percentage goals fails to timely file for a hearing with the NDIC upon being unable to meet such percentage goals or if the operator fails to timely implement production restrictions once below the applicable percentage goals. In late 2019, the overall natural gas capture rate for producers in North Dakota failed to attain the current statewide gas capture rate of 88%, and the gas capture rate will increase to 91% on November 1, 2020. To the extent that our E&P customers attempt to but cannot comply with these gas capture requirements, those customers could incur increased compliance costs to such customers or restrictions on future production, which developments could reduce demand for our services and events could have an adverse effect on our results of operations.

Crude oil and natural gas prices are volatile, and a change in these prices in absolute terms, or an adverse change in the prices of crude oil and natural gas relative to one another, could adversely affect our gross margin, business, financial condition, results of operations, cash flows and ability to make cash distributions.

We are subject to risks due to frequent and often substantial fluctuations in commodity prices. In the past, the prices of crude oil and natural gas and other commodities have been extremely volatile, and we expect this volatility to continue. Our future cash flows may be materially adversely affected if commodity markets experience significant, prolonged pricing deterioration.

The markets for and prices of crude oil and natural gas and other commodities depend on factors that are beyond our control. These factors include the supply of and demand for these commodities, which fluctuate with changes in market and economic conditions and other factors, including:

- the levels of domestic production and consumer demand;
- the availability of transportation systems with adequate capacity;
- the volatility and uncertainty of regional pricing differentials;
- worldwide economic conditions;
- worldwide political events, including actions taken by foreign crude oil and natural gas producing nations;
- worldwide weather events and conditions, including natural disasters and seasonal changes;
- events that impact global market demand, including impacts from global health epidemics and concerns, such as the coronavirus;
- the price and availability of alternative fuels;
- the effect of energy conservation measures;
- the nature and extent of governmental regulation (including environmental requirements) and taxation;
- fluctuations in demand from electric power generators and industrial customers; and
- the anticipated future prices of crude oil and natural gas, condensate and other commodities.

We may not be able to renew or replace expiring contracts at favorable rates or on a long-term basis.

We gather the crude oil and natural gas through our midstream systems under long-term contracts with Oasis Petroleum. As these contracts expire, we may have to negotiate extensions or renewals with Oasis Petroleum or enter into new contracts with other suppliers and customers. We may be unable to obtain new contracts on favorable commercial terms, if at all. We also may be unable to maintain the economic structure of a particular contract with Oasis Petroleum or the overall mix of our contract portfolio. Moreover, we may be unable to obtain areas of mutual interest from new customers in the future, and we may be unable to renew existing areas of mutual interest with current customers as and when they expire. The extension or replacement of existing contracts depends on a number of factors beyond our control, including***:***

- the level of existing and new competition to provide gathering services to our markets;
- the macroeconomic factors affecting natural gas gathering economics for our current and potential customers;
- the balance of supply and demand, on a short-term, seasonal and long-term basis, in our markets;
- the extent to which the customers in our markets are willing to contract on a long-term basis; and
- the effects of federal, state or local regulations on the contracting practices of our customers.

To the extent we are unable to renew our existing contracts on terms that are favorable to us or successfully manage our overall contract mix over time, our revenues and cash flows could decline and our ability to make distributions to our unitholders could be materially and adversely affected.

Contracts with customers are subject to additional risk in the event of a bankruptcy proceeding.

To the extent any of our customers are in financial distress or commence bankruptcy proceedings, our contracts with them, including provisions relating to dedications of production, may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. If a contract with a customer is altered or rejected in bankruptcy proceedings, we could lose some or all of the expected revenues associated with that contract, which could cause the market price of our common units to decline.

Our businesses and results of operations are subject to seasonal fluctuations, which could result in fluctuations in our operating results and common unit price.

Our business is subject to seasonal fluctuations. Demand for natural gas generally decreases during the spring and fall months and increases during the summer and winter months. Severe or prolonged winters may, however, impact our ability to complete additional well connections or complete construction projects, which may impact the rate of our growth. Severe winter weather may also impact or slow the ability of our customers to execute their planned drilling and development plans. In addition, the volumes of condensate produced at our processing facilities fluctuate seasonally, with volumes generally increasing in the winter months and decreasing in the summer months as a result of the physical properties of natural gas and comingled liquids. Severe or prolonged summers may adversely affect our results of operations.

Crude oil and natural gas production and gathering may be adversely affected by weather conditions and terrain, which in turn could negatively impact the operations of our gathering, treating and processing facilities and our construction of additional facilities.

Extended periods of below freezing weather and unseasonably wet weather conditions, especially in North Dakota and Montana, can be severe and can adversely affect crude oil and natural gas operations due to the potential shut-in of producing wells or decreased drilling activities. The result of these types of interruptions could result in a decrease in the volumes supplied to our midstream systems. Further, delays and shutdowns caused by severe weather may have a material negative impact on the continuous operations of our gathering, treating, processing and disposal systems, including interruptions in service. These types of interruptions could negatively impact our ability to meet our contractual obligations to our customers and thereby give rise to certain termination rights and/or the release of dedicated acreage. Any resulting terminations or releases could materially adversely affect our business and results of operations.

We also may be required to incur additional costs and expenses in connection with the design and installation of our facilities due to their location and surrounding terrain. We may be required to install additional facilities, incur additional capital and operating expenditures, or experience interruptions in or impairments of our operations to the extent that the facilities are not designed or installed correctly. If such facilities are not designed or installed correctly, do not perform as intended, or fail, we may be required to incur significant capital expenditures to correct or repair the deficiencies, or may incur significant damages to or loss of facilities, and our operations may be interrupted as a result of deficiencies or failures. In addition, such deficiencies may cause damage to the surrounding environment, including slope failures, stream impacts and other natural resource damages, and we may as a result also be subject to increased operating expenses or environmental penalties and fines.

Terrorist attacks or cyber-attacks could have a material adverse effect on our business, financial condition or results of operations.

Terrorist attacks or cyber-attacks may significantly affect the energy industry, including our operations and those of Oasis Petroleum and our other potential customers, as well as general economic conditions, consumer confidence and spending and market liquidity. Strategic targets, such as energy-related assets, may be at greater risk of future attacks than other targets in the United States. Also, destructive forms of protests and opposition by activists and other disruptions, including acts of sabotage or eco-terrorism, against crude 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 E&P clients' operations. Our insurance may not protect us against such occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.

The crude oil and gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations, including certain midstream activities. For example, software programs are used to manage gathering and transportation systems and for compliance reporting. The use of mobile communication devices has increased rapidly. Industrial control systems such as SCADA (supervisory control and data acquisition) now control large scale processes that can include multiple sites and long distances, such as crude oil and gas pipelines. We depend on digital technology, including information systems and related infrastructure as well as cloud applications and services, to process and record financial and operating data and to communicate with our employees and business partners. Our business partners, including vendors, service providers and financial institutions, are also dependent on digital technology. The technologies needed to conduct midstream activities make certain information the target of theft or misappropriation.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, also has increased. A cyber attack could include gaining unauthorized access to digital systems or data for purposes of misappropriating assets or sensitive information, corrupting data or causing operational disruption. SCADA-based systems are potentially vulnerable to targeted cyber attacks due to their critical role in operations.

Our technologies, systems, networks, and data and those of our business partners, may become the target of cyber attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information or other disruption of our business operations. In addition, certain cyber incidents, such as unauthorized surveillance or a cyber breach, may remain undetected for an extended period.

A cyber incident involving our information systems or data and related infrastructure, or that of our business partners, including any vendor or service provider, could disrupt our business plans and negatively impact our operations in the following ways, among others:

- supply chain disruptions, which could delay or halt development of additional infrastructure, effectively delaying the start of cash flows from the project;
- delays in delivering or failure to deliver product at the tailgate of our facilities, resulting in a loss of revenues;
- operational disruption resulting in loss of revenues;
- events of non-compliance that could lead to regulatory fines or penalties; and
- business interruptions that could result in expensive remediation efforts, distraction of management, damage to our reputation or a negative impact on the price of our units.

Our implementation of various controls and processes, including globally incorporating a risk-based cyber security framework, to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure is costly and labor intensive. Moreover, there can be no assurance that such measures will be sufficient to prevent security breaches from occurring. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Risks Inherent in an Investment in Us

Our general partner and its affiliates, including Oasis Petroleum, which owns a substantial majority of our General Partner, may have conflicts of interest with us and have limited duties to us and our unitholders, and they may favor their own interests to the detriment of us and our other common unitholders.

Oasis Petroleum controls and owns a substantial majority of our General Partner and appoints all of the officers and directors of our General Partner. All of our officers and a majority of our directors are also officers and/or directors of Oasis Petroleum. Although our General Partner has a duty to manage us in a manner that it believes is not adverse to our interest, the directors and officers of our General Partner have a fiduciary duty to manage our General Partner in a manner that is beneficial to Oasis Petroleum. Further, our directors and officers who are also directors and officers of Oasis Petroleum have a fiduciary duty to manage Oasis Petroleum in the best interests of the stockholders of Oasis Petroleum. Conflicts of interest will arise between Oasis Petroleum and any of its affiliates, including our General Partner, on the one hand, and us and our common unitholders, on the other hand. In resolving these conflicts of interest, our General Partner may favor its own interests and the interests of Oasis Petroleum 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 Oasis Petroleum to pursue a business strategy that favors us;
- Oasis Petroleum, as our anchor customer, has an economic incentive to cause us not to seek higher fees, even if such higher fees would reflect fees that could be obtained in arm’s-length, third-party transactions;
- Oasis Petroleum may choose to shift the focus of its investment and operations to areas not served by our assets;
- actions taken by our General Partner may affect the amount of cash available to pay distributions to unitholders or accelerate the right to convert subordinated units;
- the directors and officers of Oasis Petroleum have a fiduciary duty to make decisions in the best interests of the stockholders of Oasis Petroleum, which may be contrary to our interests;
- our General Partner is allowed to take into account the interests of parties other than us, such as Oasis Petroleum, in exercising certain rights under our partnership agreement, including with respect to conflicts of interest;

- except in limited circumstances, our General Partner has the power and authority to conduct our business without unitholder approval;
- our General Partner may cause us to borrow funds in order to permit the payment of cash distributions;
- disputes may arise under our agreements with Oasis Petroleum and its affiliates;
- our General Partner controls the enforcement of obligations owed to us by our General Partner and its affiliates, including our contractual commercial agreements with Oasis Petroleum;
- our General Partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership securities and the level of reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our General Partner determines the amount and timing of any cash expenditure and whether a cash expenditure is classified as a maintenance capital expenditure, which reduces operating surplus. This determination can affect the amount of cash from operating surplus that is distributed to our unitholders which, in turn, may affect the ability of the subordinated units to convert;
- our partnership agreement limits the liability of, and replaces the 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;
- common unitholders have no right to enforce obligations of our General Partner and its affiliates under agreements with us;
- contracts between us, on the one hand, and our General Partner and its affiliates, on the other, are not and will not be the result of arm's-length negotiations;
- our partnership agreement permits us to distribute up to $40.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus, which may be used to fund distributions on our subordinated units or the IDRs;
- our General Partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with its affiliates on our behalf;
- our General Partner intends to limit its liability regarding our contractual and other obligations;
- our General Partner may exercise its right to call and purchase common units if it and its affiliates own more than 80% of the common units;
- we may not choose to retain separate counsel for ourselves or for the holders of common units;
- our General Partner's affiliates may compete with us, and our General Partner and its affiliates have limited obligations to present business opportunities to us; and
- the holder or holders of our IDRs may elect to cause us to issue common units to it in connection with a resetting of incentive distribution levels without the approval of our unitholders, which may result in lower distributions to our common unitholders in certain situations.

Ongoing cost reimbursements due to our General Partner and its affiliates for services provided, which will be determined by our General Partner, may be substantial and will reduce our distributable cash.

Prior to making distributions on our common units, we will reimburse our General Partner and its affiliates for all expenses they incur on our behalf. These expenses will include all costs incurred by our General Partner and its affiliates in managing and operating us, including costs for rendering administrative staff and support services to us and reimbursements paid by our General Partner to Oasis Petroleum for customary management and general administrative services. There is no limit on the amount of expenses for which our General Partner and its affiliates may be reimbursed. Our partnership agreement provides that our General Partner will determine the expenses that are allocable to us. In addition, under Delaware partnership law, our General Partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our General Partner. To the extent our General Partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our General Partner, our General Partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of our distributable cash.

We expect to distribute a significant portion of our distributable cash to our partners, which could limit our ability to grow and make acquisitions.

We plan to distribute most of our distributable cash and will rely primarily upon extended financing sources, including commercial bank borrowings and the issuance of equity and debt securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy may cause our growth to proceed at a slower pace than that of businesses that reinvest their cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. In addition, the incurrence of commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may reduce the cash that we have available to distribute to our unitholders.

Our partnership agreement replaces our General Partner's fiduciary duties to holders of our common units with contractual standards governing its duties.

Our partnership agreement contains provisions that eliminate and replace the fiduciary standards to which our General Partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our General Partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our General Partner, or otherwise, free of fiduciary duties to us and our unitholders. This entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our General Partner may make in its individual capacity include:

- how to allocate business opportunities among us and its other affiliates;
- whether to exercise its call right;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the board of directors of the General Partner;
- how to exercise its voting rights with respect to any units it owns;
- whether to exercise its registration rights; and
- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a unitholder agrees to be bound by our partnership agreement and approves of the elimination and replacement of fiduciary duties discussed above.

Our General Partner may elect to convert the Partnership to a corporation for U.S. federal income tax purposes without unitholder consent.

Under our partnership agreement, if, in connection with the enactment of U.S. federal income tax legislation or a change in the official interpretation of existing U.S. federal income tax legislation by a governmental authority, our General Partner determines that (i) the Partnership should no longer be characterized as a partnership for U.S. federal or applicable state and local income tax purposes or (ii) common units held by unitholders other than the General Partner and its affiliates should be converted into or exchanged for interests in a newly formed entity taxed as a corporation or an entity taxable at the entity level for U.S. federal or applicable state and local income tax purposes whose sole asset is interests in the Partnership ("parent corporation"), then our General Partner may, without unitholder approval, cause the Partnership to be treated as an entity taxable as a corporation or subject to entity-level taxation for U.S. federal or applicable state and local income tax purposes, whether by election of the Partnership or conversion of the Partnership or by any other means or methods, or cause the common units held by unitholders other than the General Partner and its affiliates to be converted into or exchanged for interests in the parent corporation. Any such event may be taxable or nontaxable to our unitholders, depending on the form of the transaction. The tax liability, if any, of a unitholder as a result of such an event may vary depending on the unitholder's particular situation and may vary from the tax liability of our General Partner and Oasis Petroleum. In addition, if our General Partner causes an interest in the Partnership to be held by a parent corporation, Oasis Petroleum may choose to retain its partnership interests in us rather than convert its partnership interests into parent corporation shares.

Our partnership agreement restricts the remedies available to holders of our common units for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement:

- provides that whenever our General Partner, the board of directors of our General Partner or any committee thereof (including the conflicts committee) makes a determination or takes, or declines to take, any other action in their respective capacities, our General Partner, the board of directors of our General Partner and any committee thereof (including the conflicts committee) is required to make such determination, or take or decline to take such other action, in the absence of bad faith, and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;
- provides that our General Partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning that it believed that the decision was not adverse to the interest of our partnership;
- provides that our General Partner and its officers and directors will not be liable for monetary damages to us, our limited partners or their assignees resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our General Partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- provides that our General Partner will not be in breach of its obligations under the partnership agreement to us or our unitholders if a transaction with an affiliate or the resolution of a conflict of interest is:
    - approved by the conflicts committee of the board of directors of our General Partner, although our General Partner is not obligated to seek such approval; or
    - approved by the vote of a majority of the outstanding common units, excluding any common units owned by our General Partner and its affiliates.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our General Partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the board of directors of our General Partner approves the affiliate transaction or resolution or course of action taken with respect to the conflict of interest, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption and proving that such decision was not in good faith.

Our partnership agreement includes exclusive forum, venue and jurisdiction provisions. By purchasing a common unit, a limited partner is irrevocably consenting to these provisions regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of Delaware courts. Our partnership agreement also provides that any unitholder bringing an unsuccessful action will be obligated to reimburse us for any costs we have incurred in connection with such unsuccessful claim.

Our partnership agreement is governed by Delaware law. Our partnership agreement includes exclusive forum, venue and jurisdiction provisions designating Delaware courts as the exclusive venue for most claims, suits, actions and proceedings involving us or our officers, directors and employees. If a dispute were to arise between a limited partner and us or our officers, directors or employees, the limited partner may be required to pursue its legal remedies in Delaware which may be an inconvenient or distant location and which is considered to be a more corporate-friendly environment. In addition, if any unitholder brings any of the aforementioned claims, suits, actions or proceedings and such person does not obtain a judgment on the merits that substantially achieves, in substance and amount, the full remedy sought, then such person shall be obligated to reimburse us and our affiliates for all fees, costs and expenses of every kind and description, including but not limited to all reasonable attorneys' fees and other litigation expenses, that the parties may incur in connection with such claim, suit, action or proceeding. These provisions may increase the costs of bringing lawsuits and have the effect of discouraging lawsuits against us and our General Partner's directors and officers. The enforceability of these provisions in other companies' certificates of incorporation or similar governing documents has been challenged in legal proceedings, and it is possible that in connection with any action a court could find these provisions contained in our partnership agreement to be inapplicable or unenforceable in such action. If a court were to find these provisions inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition and results of operations and our ability to make cash distributions to our unitholders. By purchasing a common unit, a limited partner is irrevocably consenting to these provisions and potential reimbursement obligations regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of Delaware courts. The potential reimbursement obligation provision may be applied to claims alleged to arise under federal securities laws. To the extent that the potential reimbursement obligation provision is purported to apply to a claim arising under federal securities laws, it has not been judicially determined whether such a provision contradicts public policy expressed in the Securities Act of 1933, as amended (the "Securities Act"), and thus a court may conclude that the potential reimbursement obligation provision is unenforceable.

Holders of our common units have limited voting rights and are not entitled to elect our General Partner or its directors, which could reduce the price at which our common units will trade.

Compared to the holders of common stock in a corporation, unitholders have limited voting rights and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will have no right on an annual or ongoing basis to elect our General Partner or its board of directors. The board of directors of our General Partner, including the independent directors, is chosen entirely by Oasis Petroleum, as a result of it owning our General Partner, and not by our unitholders. Furthermore, if our unitholders are dissatisfied with the performance of our General Partner, they will have little ability to remove our General Partner. Unlike publicly traded corporations, we will not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which our common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if holders of our common units are dissatisfied, they cannot initially remove our General Partner without its consent.

Unitholders are currently unable to remove our General Partner without its consent because our General Partner and its affiliates, including Oasis Petroleum, own sufficient units to be able to prevent its removal. Our General Partner may not be removed except for cause by vote of the holders of at least $66^{2/3}$% of all outstanding common and subordinated units, including any units owned by our General Partner and its affiliates, voting together as a single class. As of February 19, 2020, Oasis Petroleum owns 67.5% of our outstanding common and subordinated units. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our General Partner liable for actual fraud or willful misconduct in its capacity as our General Partner.

Our General Partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our incentive distribution rights, without the approval of the conflicts committee of our General Partner's board of directors or the holders of our common units. This could result in lower distributions to holders of our common units.

Our General Partner has the right, as the initial holder of our IDRs, at any time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (50%) for the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our distributions at the time of the exercise of the reset election. Following a reset election, the minimum quarterly distribution will be adjusted to equal the reset minimum quarterly distribution, and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

If our General Partner elects to reset the target distribution levels, it will be entitled to receive a number of common units. The number of common units to be issued to our General Partner will equal the number of common units that would have entitled our General Partner to an aggregate quarterly cash distribution in the quarter prior to the reset election equal to the distribution on the IDRs in the quarter prior to the reset election. We anticipate that our General Partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion. It is possible, however, that our General Partner or a transferee could exercise this reset election at a time when it is experiencing, or expects to experience, declines in the cash distributions it receives related to its IDRs and may, therefore, desire to be issued common units rather than retain the right to receive incentive distributions based on the initial target distribution levels. This risk could be elevated if our IDRs have been transferred to a third party. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of cash distributions that our common unitholders would have otherwise received had we not issued new common units to our General Partner in connection with resetting the target distribution levels. Our General Partner may transfer all or a portion of the IDRs in the future. After any such transfer, the holder or holders of a majority of our IDRs will be entitled to exercise the right to reset the target distribution levels.

The IDRs held by our General Partner may be transferred to a third party without unitholder consent.

Our General Partner may transfer our IDRs to a third party at any time without the consent of our unitholders. If our General Partner transfers our IDRs to a third party but retains its ownership of our general partner interest, it may not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over time as it would if it had retained ownership of our IDRs. For example, a transfer of IDRs by our General Partner could reduce the likelihood of our General Partner selling or contributing additional assets to us, as our General Partner would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

Units held by persons who our General Partner determines are not "eligible holders" at the time of any requested certification in the future may be subject to redemption.

As a result of certain laws and regulations to which we are or may in the future become subject, we may require owners of our common units to certify that they are both U.S. citizens and subject to U.S. federal income taxation on our income. Units held by persons who our General Partner determines are not "eligible holders" at the time of any requested certification in the future may be subject to redemption. "Eligible holders" are holders of our common units whose (or whose owners') (i) U.S. federal income tax status or lack of proof of U.S. federal income tax status does not have and is not reasonably likely to have, as determined by our General Partner, a material adverse effect on the rates that can be charged to customers by us or our subsidiaries with respect to assets that are subject to regulation by FERC or any similar regulatory body and (ii) nationality, citizenship or other related status does not create, as determined by our General Partner, a substantial risk of cancellation or forfeiture of any property in which we have an interest. The aggregate redemption price for redeemable interests will be an amount equal to the current market price (the date of determination of which will be the date fixed for redemption) of our common units multiplied by the number of common units included among the redeemable interests. For these purposes, the "current market price" means, as of any date, the average of the daily closing prices of our common units for the 20 consecutive trading days immediately prior to such date. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our General Partner. The units held by any person the General Partner determines is not an eligible holder will not be entitled to voting rights.

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

Unitholders' voting rights are further restricted by our partnership agreement provision providing that any units held by a person or group that owns 20% or more of any class of units then outstanding, other than our General Partner, its affiliates (including Oasis Petroleum), their transferees and persons who acquired such units with the prior approval of the board of directors of our General Partner, cannot vote on any matter.

Control of our General Partner may be transferred to a third party without unitholder consent.

Our General Partner may transfer its general partner interest to a third party without the consent of our unitholders. Furthermore, our partnership agreement does not restrict the ability of the owners of our General Partner from transferring all or a portion of their respective ownership interest in our General Partner to a third party. The new owners of our General Partner would then be in a position to replace the board of directors and officers of our General Partner with their own choices and thereby exert significant control over the decisions made by the board of directors and officers. This effectively permits a "change of control" without the vote or consent of the unitholders.

We may issue additional units, including units that are senior to the common units, without unitholder approval, which would dilute unitholders' existing ownership interests.

Our partnership agreement does not limit the number of additional partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity interests of equal or senior rank will have the following effects:

- each unitholder's proportionate ownership interest in us will decrease;
- the amount of our distributable cash per unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Oasis Petroleum may sell common units in the public or private markets, which sales could have an adverse impact on the trading price of the common units.

Oasis Petroleum holds 9,075,000 common units and 13,750,000 subordinated units as of February 19, 2020. All of the subordinated units will convert into common units at the end of the subordination period and some may convert earlier. Additionally, we have agreed to provide Oasis Petroleum with certain registration rights, pursuant to which we may be required to register common and subordinated units it holds under the Securities Act and applicable state securities laws. Pursuant to the registration rights agreement and our partnership agreement, we may be required to undertake a future public or private offering of common and subordinated units. The sale of these units in public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Our General Partner's discretion in establishing cash reserves may reduce the amount of distributable cash we have to distribute to unitholders.

Our partnership agreement requires our General Partner to deduct from operating surplus the cash reserves that it determines are necessary to fund our future operating expenditures. In addition, our partnership agreement permits the General Partner to reduce distributable cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party, or to provide funds for future distributions to partners. These cash reserves will affect the amount of distributable cash we have available to distribute to unitholders.

Affiliates of our General Partner, including Oasis Petroleum, may compete with us, and neither our General Partner nor its affiliates have any obligation to present business opportunities to us except with respect to our Subject Assets and dedications contained in our commercial agreements with Oasis Petroleum.

None of our partnership agreement, our Omnibus Agreement with Oasis Petroleum, our commercial agreements with Oasis Petroleum or any other agreement in effect as of December 31, 2019 will prohibit Oasis Petroleum or any other affiliates of our General Partner from owning assets or engaging in businesses that compete directly or indirectly with us. Under the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, will not apply to our General Partner or any of its affiliates, including Oasis Petroleum and executive officers and directors of our General Partner. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us except with respect to our Subject Assets and dedications contained in our commercial agreements with Oasis Petroleum. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. Consequently, Oasis Petroleum and other affiliates of our General Partner may acquire, construct or dispose of additional midstream assets in the future without any obligation to offer us the opportunity to purchase any of those assets. As a result, competition from Oasis Petroleum and other affiliates of our General Partner could materially and adversely impact our results of operations and distributable cash.

Our General Partner has a call right that may require unitholders to sell their common units at an undesirable time or price.

If at any time our General Partner and its affiliates (including Oasis Petroleum) own more than 80% of our common units, our General Partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price equal to the greater of (i) the average of the daily closing price of our common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (ii) the highest per-unit price paid by our General Partner or any of its affiliates for common units during the 90-day period preceding the date such notice is first mailed. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or a negative return on their investment. Unitholders may also incur a tax liability upon a sale of their units. Our General Partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our General Partner from causing us to issue additional common units and then exercising its call right. If our General Partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). At the end of the subordination period, assuming no additional issuances of units (other than upon the conversion of the subordinated units), our General Partner and its affiliates will own 68.6% of our common units (excluding common units purchased by certain of our officers, directors, employees and certain other persons affiliated with us under our directed unit program).

The price of our common units may fluctuate significantly, and unitholders could lose all or part of their investment.

The market price of our common units may be influenced by many factors, some of which are beyond our control, including:

- our quarterly distributions;
- our quarterly or annual earnings or those of other companies in our industry;
- events affecting Oasis Petroleum;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions;
- the failure of securities analysts to cover our common units or changes in financial estimates by analysts;
- future sales of our common units; and
- other factors described in these "Risk Factors."

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our units.

For as long as we are an "emerging growth company," we will not be required to comply with certain disclosure requirements that apply to other public companies.

We are classified as an "emerging growth company" under the Jumpstart Our Business Startups Act of 2012 (the "JOBS Act"). For as long as we are an "emerging growth company," which may be up to five full fiscal years, unlike other public companies, we will not be required to, among other things, (1) provide an auditor's attestation report on the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act, (2) comply with any new requirements adopted by the Public Company Accounting Oversight Board requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, (3) provide certain disclosure regarding executive compensation required of larger public companies or (4) hold nonbinding advisory votes on executive compensation. We will remain an "emerging growth company" for up to five full fiscal years following the initial public offering, although we will lose that status sooner if we have more than $1.07 billion of revenues in a fiscal year, become a large accelerated filer, or issue more than $1.07 billion of non-convertible debt cumulatively over a three-year period. To the extent that we rely on any of the exemptions available to "emerging growth companies," our unitholders will receive less information about our executive compensation and internal control over financial reporting than issuers that are not "emerging growth companies." If some investors find our common units to be less attractive as a result, there may be a less active trading market for our common units and our trading price may be more volatile.

The Nasdaq does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.

Our common units are currently traded on Nasdaq. Because we are a publicly traded partnership, Nasdaq does not require us to have a majority of independent directors on our General Partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, unitholders do not have the same protections afforded to stockholders of certain corporations that are subject to all of Nasdaq corporate governance requirements.

If we are deemed an "investment company" under the Investment Company Act of 1940, it would adversely affect the price of our common units and could have a material adverse effect on our business.

Our assets consist of direct and indirect ownership interests in our DevCos. If a sufficient amount of our assets now owned or in the future acquired are deemed to be "investment securities" within the meaning of the Investment Company Act of 1940, or the Investment Company Act, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify our organizational structure or our contract rights to fall outside the definition of an investment company. Treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes, in which case we would be treated as a corporation for federal income tax purposes. As a result, we would pay federal income tax on our taxable income at the corporate tax rate, distributions to our unitholders would generally be taxed again as corporate dividends and none of our income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our distributable cash would be substantially reduced. Therefore, treatment of us as an investment company would result in a material reduction in the anticipated cash flows and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Moreover, registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase of additional interests in our DevCos from Oasis Petroleum, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add directors who are independent of us or our affiliates to our board. The occurrence of some or all of these events would adversely affect the price of our common units and could have a material adverse effect on our business.

Tax Risks

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, or if we were otherwise subjected to a material amount of entity-level taxation, then our cash flows and ability to make cash distributions to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a “qualifying income” requirement. Based upon our current operations and current Treasury Regulations, we believe we satisfy the qualifying income requirement. We have requested and received a favorable private letter ruling from the Internal Revenue Service (“IRS”) to the effect that certain of our income constitutes “qualifying income” within the meaning of Section 7704 of the Internal Revenue Code of 1986 (the “Code”). However, no ruling has been or will be requested regarding our treatment as a partnership for U.S. federal income tax purposes. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our distributable cash would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flows and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. We currently own assets and conduct business in several states that impose a margin or franchise tax. In the future, we may expand our operations. Imposition of a similar tax on us in other jurisdictions that we may expand to could substantially reduce our distributable cash. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for U.S. federal, state, local or foreign income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law or interpretation on us.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial changes or differing interpretations at any time.

From time to time, members of Congress have proposed and considered substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships, including elimination of partnership tax treatment for certain publicly traded partnerships. For example, the “Clean Energy for America Act,” which is similar to legislation that was commonly proposed during the Obama Administration, was introduced in the Senate on May 2, 2019. If enacted, this proposal would, among other things, repeal the qualifying income exception within Section 7704(d)(1)(E) of the Code, upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. There can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department’s interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership in the future.

Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any changes or other proposals will ultimately be enacted. Any future legislative changes could negatively impact the value of an investment in our common units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our common units.

If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our common units, and the costs of any such contest would reduce our distributable cash.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. Moreover, the costs of any contest between us and the IRS will result in a reduction in our distributable cash and thus will be borne indirectly by our unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us, in which case our distributable cash might be substantially reduced.

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

Our unitholders are required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Our unitholders are required to pay any U.S. federal income taxes and, in some cases, state and local income taxes on their share of our taxable income whether or not they receive cash distributions from us. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, our unitholders may be allocated taxable income and gain resulting from the sale and our distributable cash would not increase. Similarly, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result in “cancellation of indebtedness income” being allocated to our unitholders as taxable income without any increase in our distributable cash. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

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

If a unitholder sells common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and that unitholder’s tax basis in those common units. Because distributions in excess of a unitholder’s allocable share of our net taxable income decrease such unitholder’s tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the common units a unitholder sells will, in effect, become taxable income to a unitholder if it sells such common units at a price greater than its tax basis in those units, even if the price such unitholder receives is less than its original cost. In addition, because the amount realized includes a unitholder’s share of our non-recourse liabilities, if a unitholder sells its common units, a unitholder may incur a tax liability in excess of the amount of cash received from the sale.

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

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, our deduction for “business interest” is limited to the sum of our business interest income and 30% of our “adjusted taxable income.” For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization or depletion, to the extent such depreciation, amortization or depletion is not capitalized into cost of goods sold with respect to inventory. If our "business interest" is subject to limitation under these rules, our unitholders will be limited in their ability to deduct their share of any interest expense that has been allocated to them. As a result, unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

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

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

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

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

Moreover, the transferee of an interest in a partnership that is engaged in a U.S. trade or business is generally required to withhold 10% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person, and we are required to deduct and withhold from the transferee amounts that should have been withheld by the transferees but were not withheld. Because the "amount realized" includes a partner's share of the partnership's liabilities, 10% of the amount realized could exceed the total cash purchase price for the units. However, pending the issuance of final regulations, the IRS has suspended the application of this withholding rule to transfers of publicly traded interests in publicly traded partnerships. If recently promulgated regulations are finalized as proposed, such regulations would provide, with respect to transfers of publicly traded interests in publicly traded partnerships effected through a broker, that the obligation to withhold is imposed on the transferor's broker and that a partner's "amount realized" does not include a partner's share of a publicly traded partnership's liabilities for purposes of determining the amount subject to withholding. However, it is not clear when such regulations will be finalized and if they will be finalized in their current form.

We treat each purchaser of our common units as having the same tax benefits without regard to the common units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.

Because we cannot match transferors and transferees of common units, we have adopted certain methods for allocating depreciation and amortization deductions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to the use of these methods could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from any sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to a unitholder's tax returns.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month (the "Allocation Date"), instead of on the basis of the date a particular common unit is transferred. Similarly, we generally allocate (i) certain deductions for depreciation of capital additions, (ii) gain or loss realized on a sale or other disposition of our assets, and (iii) in the discretion of the General Partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of common units) may be considered to have disposed of those common units. If so, such unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered to have disposed of the loaned common units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

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

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

A successful IRS challenge to these methods or allocations could adversely affect the timing or amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain recognized from the sale of our common units, have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

Our unitholders will likely be subject to state and local taxes and income tax return filing requirements in jurisdictions where they do not live as a result of investing in our common units.

In addition to U.S. federal income taxes, our unitholders may be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements.

We currently own assets and conduct business in multiple states. Many of these states currently impose an income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose an income tax. It is our unitholders' responsibility to file all U.S. federal, foreign, state and local tax returns and pay any taxes due in these jurisdictions. Unitholders should consult with their own tax advisors regarding the filing of such tax returns, the payment of such taxes, and the deductibility of any taxes paid.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The information required by this Item 2. is contained in Item 1. Business.

Item 3. Legal Proceedings

Our operations are subject to a variety of risks and disputes normally incident to our business. As a result, we may, at any given time, be a defendant in various legal proceedings and litigation arising in the ordinary course of business. However, except as disclosed below, we are not currently subject to any potentially material litigation.

We maintain insurance policies with insurers in amounts and with coverage and deductibles that we, with the advice of our insurance advisors and brokers, believe are reasonable and prudent. We cannot, however, assure our unitholders that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

Mirada litigation. On March 23, 2017, Mirada Energy, LLC, Mirada Wild Basin Holding Company, LLC and Mirada Energy Fund I, LLC (collectively, "Mirada") filed a lawsuit against Oasis Petroleum, OPNA and OMS, seeking monetary damages in excess of $100 million, declaratory relief, attorneys' fees and costs (Mirada Energy, LLC, et al. v. Oasis Petroleum North America LLC, et al.; in the 334th Judicial District Court of Harris County, Texas; Case Number 2017-19911). Mirada asserts that it is a working interest owner in certain acreage owned and operated by Oasis Petroleum in Wild Basin. Specifically, Mirada asserts that Oasis Petroleum has breached certain agreements by: (1) failing to allow Mirada to participate in Oasis Petroleum's midstream operations in Wild Basin; (2) refusing to provide Mirada with information that Mirada contends is required under certain agreements and failing to provide information in a timely fashion; (3) failing to consult with Mirada and failing to obtain Mirada's consent prior to drilling more than one well at a time in Wild Basin; and (4) overstating the estimated costs of proposed well operations in Wild Basin. Mirada seeks a declaratory judgment that Oasis Petroleum be removed as operator in Wild Basin at Mirada's election and that Mirada be allowed to elect a new operator; certain agreements apply to Oasis Petroleum and Mirada and Wild Basin with respect to this dispute; Oasis Petroleum be required to provide all information within its possession regarding proposed or ongoing operations in Wild Basin; and Oasis Petroleum not be permitted to drill, or propose to drill, more than one well at a time in Wild Basin without obtaining Mirada's consent. Mirada also seeks a declaratory judgment with respect to Oasis Petroleum's current midstream operations in Wild Basin. Specifically, Mirada seeks a declaratory judgment that Mirada has a right to participate in Oasis Petroleum's Wild Basin midstream operations, consisting of produced and flowback water disposal, crude oil gathering and natural gas gathering and processing; that, upon Mirada's election to participate, Mirada is obligated to pay its proportionate costs of Oasis Petroleum's midstream operations in Wild Basin; and that Mirada would then be entitled to receive a share of revenues from the midstream operations and would not be charged any amount for its use of these facilities for production from the "Contract Area."

On June 30, 2017, Mirada amended its original petition to add a claim that Oasis Petroleum has breached certain agreements by charging Mirada for midstream services provided by its affiliates and to seek a declaratory judgment that Mirada is entitled to be paid its share of total proceeds from the sale of hydrocarbons received by OPNA or any affiliate of OPNA without deductions for midstream services provided by OPNA or its affiliates.

On February 2, 2018 and February 16, 2018, Mirada filed a second and third amended petition, respectively. In these filings, Mirada alleged new legal theories for being entitled to enforce the underlying contracts and added Bighorn DevCo, Bobcat DevCo and Beartooth DevCo as defendants, asserting that these entities were created in bad faith in an effort to avoid contractual obligations owed to Mirada.

On March 2, 2018, Mirada filed a fourth amended petition that described Mirada's alleged ownership and assignment of interests in assets purportedly governed by agreements at issue in the lawsuit. On August 31, 2018, Mirada filed a fifth amended petition that added the Partnership as a defendant, asserting that it was created in bad faith in an effort to avoid contractual obligations owed to Mirada.

On July 2, 2019, Oasis Petroleum, OPNA, OMS, the Partnership, Bighorn DevCo, Bobcat DevCo and Beartooth DevCo (collectively "Oasis Entities") counterclaimed against Mirada for a judgment declaring that Oasis Entities are not obligated to purchase, manage, gather, transport, compress, process, market, sell or otherwise handle Mirada's proportionate share of oil and gas produced from OPNA-operated wells. The counterclaim also seeks attorney's fees, costs and expenses.

On November 1, 2019, Mirada filed a sixth amended petition that stated that Mirada seeks in excess of $200 million in damages and asserted that OMS is an agent of OPNA and OPNA, OMS, the Partnership, Bighorn DevCo, Bobcat DevCo and Beartooth DevCo are agents of Oasis Petroleum. Mirada also changed its allegation that it may elect a new operator for the subject wells to instead allege that Mirada may remove Oasis Petroleum as operator.

On November 1, 2019, the Oasis Entities amended their counterclaim against Mirada for a judgment declaring that a provision in one of the agreements does not incorporate by reference any provisions in a certain participation agreement and joint operating agreement. The additional counterclaim also seeks attorney's fees, costs and expenses. On the same day, the Oasis Entities filed an amended answer asserting additional defenses against Mirada's claims.

Oasis Petroleum and the Partnership believe that Mirada's claims are without merit, that Oasis Petroleum has complied with its obligations under the applicable agreements and that some of Mirada's claims are grounded in agreements that do not apply to Oasis Petroleum. Oasis Petroleum filed answers denying all of Mirada's claims and intends and continues to vigorously defend against Mirada’s claims. Discovery is ongoing, and each of the parties has made a number of procedural filings and motions, and additional filings and motions can be expected over the course of the claim. Trial is scheduled for May 2020. Neither the Partnership nor Oasis Petroleum can predict or guarantee the ultimate outcome or resolution of such matter. If such matter were to be determined adversely to the Partnership's or Oasis Petroleum’s interests, or if the Partnership or Oasis Petroleum were forced to settle such matter for a significant amount, such resolution or settlement could have a material adverse effect on the Partnership's business, financial condition, results of operations, and cash flows. Such an adverse determination could materially impact Oasis Petroleum’s ability to operate its properties in Wild Basin or develop its identified drilling locations in Wild Basin on its current development schedule. A determination that Mirada has a right to participate in Oasis Petroleum’s midstream operations could materially reduce the interests of Oasis Petroleum and the Partnership in the Partnership's current assets and future midstream opportunities and related revenues in Wild Basin. Under the Omnibus Agreement the Partnership entered into with Oasis Petroleum in connection with the closing of the initial public offering, Oasis Petroleum agreed to indemnify the Partnership for any losses resulting from this litigation. However, the Partnership cannot guarantee that such indemnity will fully protect the Partnership from the adverse consequences of any adverse ruling.

Solomon litigation. On or about August 28, 2019, Oasis Petroleum LLC, a wholly-owned subsidiary of Oasis Petroleum (“OP LLC”), was named as a defendant in the lawsuit styled *Andrew Solomon, on behalf of himself and those similarly situated vs. Oasis Petroleum LLC*, pending in the United States District Court for the District of North Dakota. The lawsuit alleged violations of the federal Fair Labor Standards Act (the “FLSA”) and Title 29 of the North Dakota Century Code (“Title 29”) as the result of OP LLC’s alleged practice of paying the plaintiff and similarly situated current and former employees overtime at rates less than required by applicable law, or failing to pay for certain overtime hours worked. The lawsuit requested that: (i) its federal claims be advanced as a collective action, with a class of all operators, technicians and all other employees in substantially similar positions employed by OP LLC who were paid hourly for at least one week during the three year period prior to the commencement of the lawsuit, who worked 40 or more hours in at least one workweek and/or eight or more hours on at least one workday; and (ii) its state claims be advanced as a class action, with a class of all operators, technicians, and all other employees in substantially similar positions employed by OP LLC in North Dakota during the two year period prior to the commencement of the lawsuit, who worked 40 or more hours in at least one workweek and/or worked eight or more hours in a day on at least one workday. No motion has been filed for class certification, and the Partnership cannot predict whether such motion will be filed or a class certified.

Oasis Petroleum believes that Mr. Solomon’s claims are without merit and that OP LLC has complied with its obligations under the FLSA and Title 29. OP LLC has filed an answer denying all of Mr. Solomon’s claims and intends to vigorously defend against the claims. The Partnership cannot predict or guarantee the ultimate outcome or resolutions of such matter. If such matter were to be determined adversely to Oasis Petroleum’s interests, or if Oasis Petroleum were forced to settle such matter for a significant amount, such resolution or settlement could have a material adverse effect on the Partnership’s business, financial condition, results of operations or cash flows.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Market for Registrant’s Common Equity. Since December 24, 2019, our common units have been listed and traded on the Nasdaq under the symbol “OMP.” Before December 24, 2019, our common units were listed and traded on the New York Stock Exchange.

Holders. As of February 19, 2020, the number of record holders of our publicly traded common units was four. Based on inquiry, management believes that the number of beneficial owners of our common units is approximately 8,563.

Intent to Distribute the Minimum Quarterly Distribution. Under our current cash distribution policy, we intend to distribute to the holders of our common units and subordinated units on a quarterly basis at least the minimum quarterly distribution of $0.3750 per unit, or $1.50 per unit on an annualized basis, to the extent we have sufficient available cash after the establishment of cash reserves and the payment of costs and expenses, including reimbursement of expenses to our General Partner. However, there is no guarantee that we will pay the minimum quarterly distribution on our units in any quarter. The amount of distributions paid under our cash distribution policy and the decision to make any distribution will be determined by our General Partner, taking into consideration the terms of our partnership agreement.

General Partner Interest. Our General Partner owns a non-economic general partner interest in us, which does not entitle it to receive cash distributions. However, our General Partner may in the future own common units or other equity interests in us and will be entitled to receive distributions on any such interests.

Incentive Distribution Rights. IDRs represent the right to receive increasing percentages (15%, 25% and 50%) of quarterly distributions from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. Our General Partner currently holds all of the IDRs in the Partnership, but may transfer these rights separately from its general partner interest.

If for any quarter:

- we have distributed cash from operating surplus to the common unitholders and subordinated unitholders in an amount equal to the minimum quarterly distribution; and
- we have distributed cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then we will make additional distributions from operating surplus for that quarter among the unitholders and the holders of the IDRs in the following manner:

- first, to all unitholders, pro rata, until each unitholder receives a total of $0.43125 per unit for that quarter, or the first target distribution;
- second, 85% to all common unitholders and subordinated unitholders, pro rata, and 15% to the holders of our IDRs, until each unitholder receives a total of $0.46875 per unit for that quarter, or the second target distribution;
- third, 75% to all common unitholders and subordinated unitholders, pro rata, and 25% to the holders of our IDRs, until each unitholder receives a total of $0.56250 per unit for that quarter, or the third target distribution; and
- thereafter, 50% to all common unitholders and subordinated unitholders, pro rata, and 50% to the holders of our IDRs.

Percentage Allocations of Distributions From Operating Surplus. The following table illustrates the percentage allocations of distributions from operating surplus between the unitholders and the holders of our IDRs based on the specified target distribution levels. The amounts set forth under the column heading “Marginal Percentage Interest in Distributions” are the percentage interests of the holders of our IDRs and the unitholders in any distributions from operating surplus we distribute up to and including the corresponding amount in the column “Total Quarterly Distribution Per Unit.” The percentage interests shown for our unitholders and the holders of our IDRs for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below assume there are no arrearages on common units.

	Total Quarterly Distribution Per Unit	Marginal Percentage Interest in Distributions	
		Unitholders	IDR Holders
Minimum Quarterly Distribution	up to $0.3750	100 %	— %
First Target Distribution	above $0.3750 up to $0.4313	100 %	— %
Second Target Distribution	above $0.4313 up to $0.4688	85 %	15 %
Third Target Distribution	above $0.4688 up to $0.5625	75 %	25 %
Thereafter	above $0.5625	50 %	50 %

Subordination Units and Subordination Period

General

Our partnership agreement provides that, during the subordination period (described below), the common unitholders will have the right to receive distributions from operating surplus each quarter in an amount equal to $0.3750 per common unit, which amount is defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on our common units from prior quarters, before any distributions from operating surplus may be made on our subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, our subordinated units will not be entitled to receive any distributions from operating surplus for any quarter until our common units have received the minimum quarterly distribution from operating surplus for such quarter plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Furthermore, no arrearages will be paid on our subordinated units. The practical effect of our subordinated units is to increase the likelihood that during the subordination period there will be sufficient cash from operating surplus to pay the minimum quarterly distribution on our common units.

Determination of Subordination Period

Oasis Petroleum owns all of our subordinated units. The subordination period began on September 25, 2017 and, except as described below, will expire on the first business day after the distribution to unitholders in respect of any quarter, beginning with the quarter ended December 31, 2020, if each of the following has occurred:

- for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date, aggregate distributions from operating surplus equaled or exceeded the sum of the minimum quarterly distribution multiplied by the total number of common and subordinated units outstanding in each quarter in each period;
- for the same three consecutive, non-overlapping four-quarter periods, the "adjusted operating surplus" equaled or exceeded the sum of the minimum quarterly distribution multiplied by the total number of common and subordinated units outstanding during each quarter on a fully diluted weighted average basis; and
- there are no arrearages in payment of the minimum quarterly distribution on our common units.

Early Termination of Subordination Period

Notwithstanding the foregoing, the subordination period will automatically terminate, and all of the subordinated units will convert into common units on a one-for-one basis, on the first business day after the distribution to unitholders in respect of any quarter, beginning with the quarter ended December 31, 2018, if each of the following has occurred:

- for one four-quarter period immediately preceding that date, aggregate distributions from operating surplus exceeded 150.0% of the minimum quarterly distribution multiplied by the total number of common units and subordinated units outstanding in each quarter in the period;
- for the same four-quarter period, the "adjusted operating surplus" equaled or exceeded 150.0% of the sum of the minimum quarterly distribution multiplied by the total number of common and subordinated units outstanding during each quarter on a fully diluted weighted average basis, plus the related distribution on the IDRs; and
- there are no arrearages in payment of the minimum quarterly distributions on our common units.

Expiration of the Subordination Period

When the subordination period ends, each outstanding subordinated unit will convert into one common unit, which will then participate pro-rata with the other common units in distributions.

Unregistered Sales of Securities. There were no sales of unregistered securities during the year ended December 31, 2019.

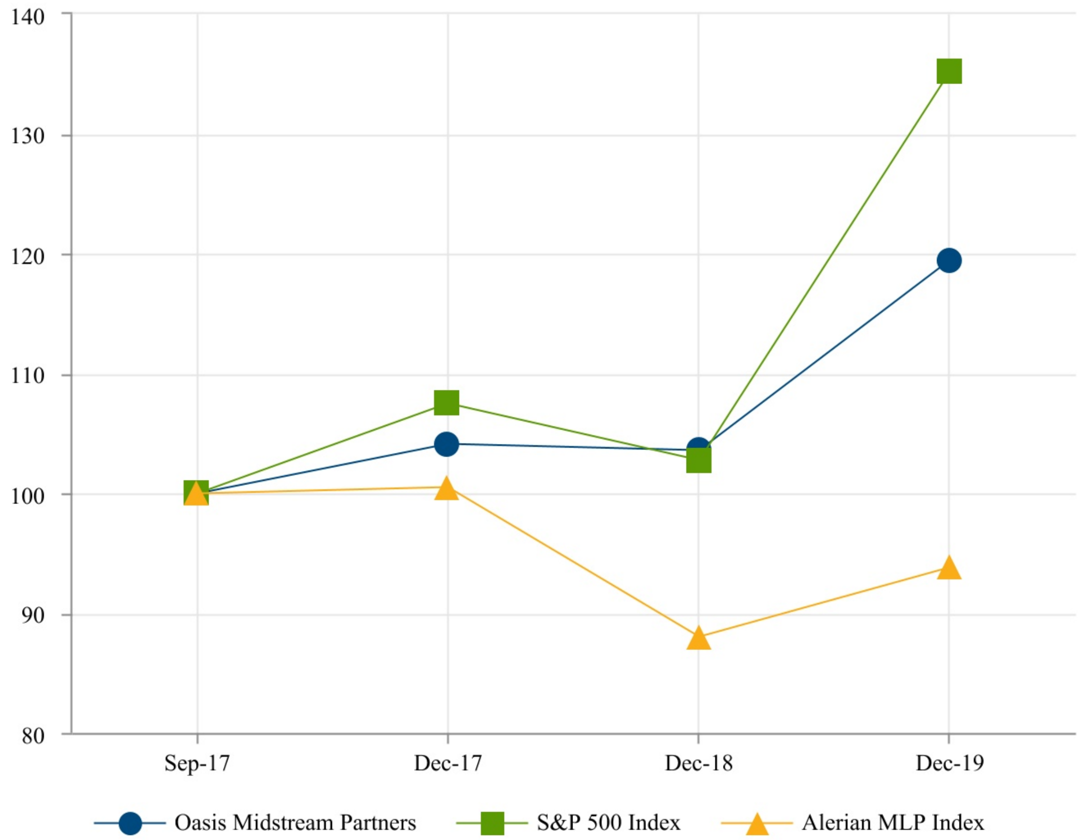
Securities Authorized for Issuance Under Equity Compensation Plans. On September 11, 2017, our General Partner adopted the Oasis Midstream Partners LP 2017 Long Term Incentive Plan (the "LTIP"), effective as of September 20, 2017. As of December 31, 2019, the LTIP permits the issuance of up to 2,455,408 common units. See Note 12 to our consolidated financial statements. See "Part III. Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" for information regarding our equity compensation plan as of December 31, 2019.

Unit Performance Graph. The following performance graph and related information is "furnished" with the SEC and shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act or the Exchange Act, except to the extent that we specifically request that such information be treated as "soliciting material" or specifically incorporate such information by reference into such a filing.

The performance graph shown below compares the cumulative total return to our public common unitholders as compared to the cumulative total returns on the Standard and Poor's 500 Index ("S&P 500") and the Alerian MLP Index (NYSE: AMZ) for the period since our initial public offering in September 2017 through December 2019. The comparison was prepared based upon the following assumptions:

1. $100 was invested in our common units, the S&P 500 and the Alerian MLP Index on September 21, 2017 at the closing price on such date; and

2. Dividends were reinvested.



Item 6. Selected Financial Data

Set forth below is our summary historical consolidated financial data for the years ended December 31, 2015 through 2019. This information may not be indicative of our future results of operations, financial position and cash flows and should be read in conjunction with the consolidated financial statements and related notes appearing in “Item 8. Financial Statements and Supplementary Data” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” presented elsewhere in this Annual Report on Form 10-K. We believe that the assumptions underlying the preparation of our historical consolidated financial statements are reasonable.

	Year Ended December 31,				
	2019(1)	2018(1)	2017(2)	2016(2)	2015(2)
	(In thousands, except per unit data)				
Statement of operations data:					
Total revenues	$ 410,191	$ 273,770	$ 182,216	$ 120,852	$ 104,696
Operating income	232,772	150,346	102,363	70,940	58,095
Net income	215,231	147,752	72,547	40,128	32,442
Net income attributable to OMP LP	117,656	50,055	11,638	—	—
Per unit data:					
Common units – basic	$ 3.41	$ 1.82	$ 0.43	$ —	$ —
Common units – diluted	3.41	1.82	0.43	—	—
Cash distribution declared per limited partner unit	2.02	1.68	0.40	—	—
Balance sheet data:					
Total property, plant and equipment, net	$ 1,056,521	$ 879,848	$ 619,580	$ 431,535	$ 265,409
Total assets(3)	1,154,669	973,892	709,906	450,028	280,763
Long-term debt	458,500	318,000	78,000	—	—
Total equity	604,628	557,672	560,020	331,675	204,856
Other financial data:					
Net cash provided by operating activities	$ 252,539	$ 206,343	$ 79,843	$ 72,086	$ 54,143
Net cash used in investing activities	(250,771)	(283,025)	(255,944)	(157,866)	(120,234)
Net cash provided by (used in) financing activities	(4,249)	82,448	176,984	85,780	66,091

(1) Financial data retrospectively adjusted for the transfer of net assets between entities under common control. See Note 4 to our consolidated financial statements.
(2) Includes financial data of the Predecessor for periods prior to the initial public offering on September 25, 2017.
(3) Upon adoption of the new lease standard in 2019, we recognized operating lease right-of-use (“ROU”) assets of $4.1 million. We did not have any finance leases as of the date of adoption. See Note 9 to our consolidated financial statements for a description of our operating and finance leases.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes appearing under “Item 8. Financial Statements and Supplementary Data” in this Annual Report on Form 10-K. The following discussion contains “forward-looking statements” that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results, and the differences can be material. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See “Cautionary note regarding forward-looking statements.”

This Annual Report on Form 10-K includes the assets, liabilities and results of operations of the Predecessor for periods prior to the initial public offering on September 25, 2017. This Annual Report on Form 10-K also includes the assets, liabilities and results of operations attributable to the Delaware Predecessor for the periods from February 14, 2018, the date on which Oasis Petroleum closed on its acquisition to enter the Delaware Basin, through November 1, 2019, the effective date of the 2019 Delaware Acquisition. Our future results of operations may not be comparable to the Predecessor’s historical results of operations or the Delaware Predecessor’s historical results of operations. Please read “Items Affecting Comparability of Our Financial Condition and Results of Operations.”

Overview

We are a growth-oriented, fee-based master limited partnership formed by our sponsor, Oasis Petroleum (Nasdaq: OAS), to own, develop, operate and acquire a diversified portfolio of midstream assets in North America that are integral to the crude oil and natural gas operations of Oasis Petroleum and are strategically positioned to capture volumes from other producers. Our midstream operations are performed within the Williston Basin and the Delaware Basin. We generate substantially all of our revenues through long-term, fixed-fee contracts pursuant to which we provide crude oil, natural gas and water-related midstream services for Oasis Petroleum. We expect to grow acquisitively through accretive, dropdown acquisitions, as well as organically as Oasis Petroleum continues to develop its acreage. Additionally, we expect to grow by continuing to offer our services to third parties and through acquisitions of midstream assets from third parties.

In the Williston Basin, we divide our operations into two primary areas with developed midstream infrastructure, both of which are supported by significant acreage dedications from Oasis Petroleum. In Wild Basin, we have acreage dedications from Oasis Petroleum in which we have the right to provide crude oil, natural gas and water services to support Oasis Petroleum’s existing and future volumes. Outside of Wild Basin, we have acreage dedications from Oasis Petroleum for produced and flowback water services and freshwater services. We expanded our operations to the Delaware Basin in the fourth quarter of 2019 when, effective November 1, 2019, Oasis Petroleum assigned to us certain crude oil gathering and produced and flowback water gathering and disposal assets under development to support Oasis Petroleum’s production in the Delaware Basin (the “2019 Delaware Acquisition”). On November 1, 2019, we also entered into long-term commercial agreements with Oasis Petroleum, pursuant to which Oasis Petroleum dedicated to us acreage in the Delaware Basin for crude oil gathering and produced and flowback water gathering and disposal services. We have also received certain commitments and acreage dedications from third parties in the Williston Basin and the Delaware Basin, in which we have the right to provide our full suite of midstream services to support existing and future third party volumes.

We conduct our business through our ownership of our DevCos, two of which are jointly-owned with Oasis Petroleum. As of December 31, 2019, we own a 100% equity interest in Bighorn DevCo, a 35.3% equity interest in Bobcat DevCo, a 70% equity interest in Beartooth DevCo and a 100% equity interest in Panther DevCo. As of December 31, 2019, Oasis Petroleum owns a 64.7% and 30% non-controlling equity interest in Bobcat DevCo and Beartooth DevCo, respectively.

We are party to long-term, fixed-fee contracts with wholly-owned subsidiaries of Oasis Petroleum for natural gas services (gathering, compression, processing and gas lift), crude oil services (gathering, stabilization, blending and storage), produced and flowback water services (gathering and disposal) and freshwater services (fracwater and flushwater supply and distribution). We are also a party to the long-term, FERC-regulated transportation services agreement governing the transportation of crude oil via pipeline from the Wild Basin area to Johnson’s Corner. We generate substantially all of our revenues through these contracts, which minimizes our direct exposure to commodity prices. We have also entered into multiple agreements and transactions with third parties to provide our full suite of midstream services, increasing our customer diversification. We do not take ownership of the crude oil or natural gas that we handle for Oasis Petroleum; however, we take ownership of natural gas under certain purchase arrangements with third parties. We believe our contractual arrangements provide us with stable and predictable cash flows over the long-term. Oasis Petroleum has also granted us a ROFO, which converts into a ROFR from any successor upon a change of control of Oasis Petroleum, with respect to its retained interests in two of our DevCos and any other midstream assets that Oasis Petroleum or any Oasis Petroleum successor builds with respect to its acreage at the time of our initial public offering and elects to sell in the future.

Highlights

Significant financial and operating results for the year ended December 31, 2019 include:

- Net income was $215.2 million and net cash provided by operating activities was $252.5 million.
- Adjusted EBITDA was $269.5 million and Adjusted EBITDA attributable to the Partnership was $158.9 million. Adjusted EBITDA is a non-GAAP financial measure. See "Non-GAAP Financial Measures" below.
- Distributable Cash Flow ("DCF") was $133.9 million, an increase of approximately 125% from 2018. DCF is a non-GAAP financial measure. See "Non-GAAP Financial Measures" below.
- During 2019, natural gas processing volumes were 221.6 MMscfpd, an increase of 115% from 2018. Third party natural gas processing volumes approximated 30% of total natural gas processing volumes in 2019.
- Entered into multiple agreements with third party producers in the Williston Basin and the Delaware Basin in 2019.
- Began executing services to Oasis Petroleum and third parties in the Delaware Basin for crude oil and produced water services. Oasis Petroleum assigned certain crude oil and produced water assets in the Delaware Basin to OMP, effective November 1, 2019. In connection with the assignment of assets, OMP reimbursed Oasis Petroleum approximately $24.9 million and assumed approximately $10.0 million of liabilities incurred by Oasis Petroleum prior to the effective date.

The following table summarizes the throughput volumes, operating income, depreciation and amortization and capital expenditures ("CapEx") of each of our DevCos for the periods presented:

	Year Ended December 31,	
	2019[(1)]	2018[(1)]
	(In thousands, except throughput volumes)	
Bighorn DevCo		
Crude oil services volumes (MBopd)	49.2	43.6
Natural gas services volumes (MMscfpd)	221.6	102.8
Operating income	$ 62,657	$ 22,147
Depreciation and amortization	13,032	11,409
Capital expenditures	17,850	74,303
Bobcat DevCo		
Crude oil services volumes (MBopd)	39.2	36.1
Natural gas services volumes (MMscfpd)	265.8	147.7
Water services volumes (MBowpd)	53.4	49.4
Operating income	$ 110,566	$ 74,282
Depreciation and amortization	13,201	9,030
Capital expenditures	134,539	141,666
Beartooth DevCo		
Water services volumes (MBowpd)	136.5	137.7
Operating income	$ 56,610	$ 55,296
Depreciation and amortization	9,446	7,965
Capital expenditures	19,596	51,212
Panther DevCo		
Crude oil service volumes (MBopd)	1.4	—
Water service volumes (MBowpd)	19.8	11.8
Operating income	$ 5,810	$ 1,579
Depreciation and amortization	679	5
Capital expenditures	40,035	9,423
Oasis Midstream Partners LP		
DevCo operating income	$ 235,643	$ 153,304
Public company expenses	2,871	2,959
Partnership operating income	232,772	150,345
Depreciation and amortization	36,358	28,409
Equity-based compensation expense	378	356
Capitalized interest	905	4,870
Maintenance capital expenditures	17,621	6,915
Expansion capital expenditures	194,399	269,689
Total capital expenditures	212,925	281,474

(1) Retrospectively adjusted for the transfer of net assets between entities under common control. See Note 4 to our consolidated financial statements.

How We Evaluate Our Operations

We use a variety of financial and operating metrics to analyze our operating results and profitability. These metrics are significant factors in assessing our operating results and profitability and include: (i) throughput volumes, (ii) Adjusted EBITDA, (iii) Distributable Cash Flow, (iv) capital expenditures, (v) operating expenses and (vi) general and administrative expenses. Adjusted EBITDA and Distributable Cash Flow are supplemental non-GAAP financial measures. For a definition of these non-GAAP financial measures and a reconciliation to the most directly comparable GAAP measure, see "Non-GAAP Financial Measures" below.

Throughput Volumes

The amount of revenue we generate primarily depends on the volumes of crude oil, natural gas and water for which we provide midstream services. By connecting new producing wells to our gathering systems and by increasing capacity on our systems, we are able to increase volumes. Additionally, by performing routine maintenance and monitoring of our infrastructure, we are able to minimize service interruptions on our gathering systems.

Under our commercial agreements with Oasis Petroleum and its wholly-owned subsidiaries in the Williston Basin, we provide (i) natural gas gathering, compression, processing and gas lift services, with acreage dedications in the Wild Basin operating area and firm capacity for gas attributable to such acreage; (ii) crude oil gathering, stabilization, blending and storage services, with acreage dedications in the Wild Basin operating area and firm capacity for crude oil attributable to such acreage; (iii) produced and flowback water gathering and disposal services, with acreage dedications in the Wild Basin operating area and firm capacity for produced and flowback water attributable to such acreage; (iv) produced and flowback water gathering and disposal services, with acreage dedications that includes the Alger, Cottonwood, Hebron, Indian Hills and Red Bank operating areas; and (v) freshwater supply and distribution services, with acreage dedications that include the Hebron, Indian Hills, Red Bank and Wild Basin operating areas. In addition, we are party to a FERC-regulated crude oil transportation services agreement, which provides for crude oil transportation from the Wild Basin operating area to Johnson's Corner with up to 75,000 barrels per day of operating capacity and firm capacity for committed shippers.

Under our commercial agreements with Oasis Petroleum and its wholly-owned subsidiaries in the Delaware Basin, we provide (i) crude oil gathering services, with acreage dedications and firm capacity for crude oil attributable to such acreage and (ii) produced and flowback water gathering and disposal services, with acreage dedications and firm capacity for produced and flowback water attributable to such acreage.

Throughput volumes are affected by changes in the supply of and demand for crude oil and natural gas in the markets served directly or indirectly by our assets. Because the production rate of a well declines over time, we must continually obtain new supplies of crude oil, natural gas and produced and flowback water to maintain or increase the throughput volumes on our midstream systems. Because freshwater supply and distribution services are largely dependent on well completion activities, our ability to provide freshwater supply and distribution services is contingent on our customers drilling and completing new wells in and around our freshwater infrastructure. Our customers' willingness to engage in new development activity is determined by a number of factors, the most important of which are the prevailing and projected prices of crude oil and natural gas, the cost to drill, complete and operate a well, expected well performance, the availability and cost of capital and environmental and government regulations. We generally expect the level of development activity to positively correlate with long-term trends in commodity prices and similarly, production levels to positively correlate with development activity.

Our ability to maintain or increase existing throughput volumes and obtain new supplies of crude oil, natural gas and produced, flowback and freshwater are impacted by:

- successful development activity by Oasis Petroleum on our dedicated acreage and our ability to fund the capital costs required to connect our infrastructure assets to new wells;
- our ability to utilize the remaining uncommitted capacity on, or add additional capacity to, our infrastructure assets;
- the level of workovers and recompletions of wells on existing pad sites to which our infrastructure assets are connected;
- our ability to identify and execute organic expansion projects to capture incremental volumes from Oasis Petroleum and third parties;
- our ability to compete for volumes from successful new wells in the areas in which we operate outside of our dedicated acreage;
- our ability to provide crude oil, natural gas and water-related midstream services with respect to volumes produced on acreage that has been released from commitments with our competitors; and
- our ability to obtain financing for acquiring incremental assets in dropdown transactions from Oasis Petroleum.

We actively monitor producer activity in the areas served by our infrastructure assets to identify opportunities to connect new wells to our gathering systems.

Adjusted EBITDA and Distributable Cash Flow

We define Adjusted EBITDA as earnings before interest expense (net of capitalized interest), income taxes, depreciation, amortization, impairment, equity-based compensation expenses and other similar non-cash adjustments. We define Adjusted EBITDA attributable to the Partnership as Adjusted EBITDA less Adjusted EBITDA attributable to Oasis Petroleum's retained interests in two of our DevCos. We define Distributable Cash Flow as Adjusted EBITDA attributable to the Partnership less cash paid for interest and maintenance capital expenditures attributable to the Partnership.

Adjusted EBITDA and Distributable Cash Flow are not presentations made in accordance with GAAP. These non-GAAP supplemental financial measures may be used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies, to assess:

- our operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to historical cost basis or, in the case of Adjusted EBITDA, financing methods;
- the ability of our assets to generate sufficient cash flow to make distributions to our unitholders;
- our ability to incur and service debt and fund capital expenditures; and
- the viability of acquisitions and other capital expenditure projects and the returns on investment of various investment opportunities.

We believe that the presentation of Adjusted EBITDA and Distributable Cash Flow provides useful information to investors in assessing our financial condition and results of operations. The GAAP measures most directly comparable to Adjusted EBITDA and Distributable Cash Flow are net income and net cash provided by operating activities, respectively. Adjusted EBITDA and Distributable Cash Flow should not be considered as alternatives to GAAP net income, income from operations, net cash provided by operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Adjusted EBITDA and Distributable Cash Flow have important limitations as analytical tools because they exclude some, but not all, items that affect net income and net cash provided by operating activities. Adjusted EBITDA or Distributable Cash Flow should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Additionally, because Adjusted EBITDA and Distributable Cash Flow may be defined differently by other companies in our industry, our definition of Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of other companies, thereby diminishing their utility. For a further discussion of Adjusted EBITDA and Distributable Cash Flow and reconciliations of Adjusted EBITDA and Distributable Cash Flow to net income and net cash provided by operating activities, see "Non-GAAP Financial Measures" below.

Capital Expenditures

The midstream energy business is capital intensive; thus, our operations require capital investments to maintain, expand, upgrade or enhance our existing operations. Our capital requirements are categorized as either:

Maintenance capital expenditures, which are cash expenditures (including expenditures for the construction or development of new capital assets or the replacement, improvement or expansion of existing capital assets) made to maintain, over the long- term, system operating capacity, operating income or revenue. Examples of maintenance capital expenditures are expenditures to repair, refurbish and replace pipelines, to maintain equipment reliability, integrity and safety and to comply with environmental laws and regulations. In addition, we designate a portion of our capital expenditures to connect new wells to maintain gathering throughput as maintenance capital expenditures to the extent such capital expenditures are necessary to maintain, over the long term, system operating capacity, operating income or revenue. Cash expenditures made solely for investment purposes will not be considered maintenance capital expenditures; or

Expansion capital expenditures, which are cash expenditures to acquire additional interests in our midstream assets and to construct new midstream infrastructure and those expenditures incurred in order to extend the useful lives of our assets, reduce costs, increase revenues or increase system throughput or capacity from current levels, including well connections that increase existing system operating capacity, operating income or revenue. Examples of expansion capital expenditures include the acquisition of additional interests in our DevCos, and the construction, development or acquisition of additional midstream assets, in each case, to the extent such capital expenditures are expected to increase, over the long term, system operating capacity, operating income or revenue. In the future, if we make acquisitions that increase system operating capacity, operating income or revenue, the associated capital expenditures may also be considered expansion capital expenditures.

Operating Expenses

We seek to maximize the profitability of our operations by effectively managing operating expenses, including operating and maintenance expenses and costs of product sales. Operating and maintenance expenses are primarily comprised of direct labor, utility costs, insurance premiums, third-party service provider costs, related property taxes and other non-income taxes, expenditures to repair, refurbish and replace facilities and to maintain equipment reliability, integrity and safety. Cost of product sales are primarily comprised of freshwater purchases, natural gas purchases from third parties, and certain operating costs to maintain our freshwater assets and natural gas processing plants.

These operating expenses fluctuate from period to period depending on the mix of activities performed during any specified period and the timing of these expenses. Because many of these expenses are fixed in nature, we expect to lower operating expenses as a percentage of revenue as we add incremental volumes onto our gathering systems. We will seek to manage our operating expenditures by scheduling periodic maintenance on our assets in order to minimize significant variability in these expenditures and their impact on our cash flow.

General and Administrative Expenses

We are party to a 15-year services and secondment agreement with Oasis Petroleum (the “Services and Secondment Agreement”), pursuant to which Oasis Petroleum performs certain general and administrative (“G&A”) services on our behalf, such as legal, corporate recordkeeping, planning, budgeting, regulatory, accounting, billing, business development, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, investor relations, cash management and banking, payroll, internal audit, tax and engineering (collectively “G&A services”). In addition, Oasis Petroleum has seconded to us certain of its employees to operate, construct, manage and maintain our assets. The Services and Secondment Agreement requires us to reimburse Oasis Petroleum for direct G&A expenses incurred for the provision of these services. Oasis Petroleum charges us a combination of direct and indirect allocated charges for G&A services using certain estimates and assumptions of the expenses attributable to our operations. Management believes these estimates and assumptions are reasonable. In addition, we incur costs as a publicly traded partnership which consist primarily of accounting and audit fees, legal fees, board and director expenses, and equity-based compensation expenses.

Items Affecting Comparability of Our Financial Condition and Results of Operations

This Annual Report on Form 10-K includes assets, liabilities and results of operations attributable to the Predecessor for periods prior to the date of the initial public offering on September 25, 2017. This Annual Report on Form 10-K also includes assets, liabilities and results of operations attributable to the Delaware Predecessor for the periods from February 14, 2018, the date on which Oasis Petroleum closed on its acquisition to enter the Delaware Basin, through November 1, 2019, the effective date of the 2019 Delaware Acquisition. Our future results of operations may not be comparable to the historical results of operations of the Predecessor or Delaware Predecessor for the following reasons:

Revenues. Historically, the Predecessor and Delaware Predecessor had provided substantially all of their services to Oasis Petroleum operated wells at prevailing market rates. In connection with the initial public offering, we entered into 15-year, fixed fee contracts for natural gas services (gathering, compression, processing and gas lift), crude oil services (gathering, stabilization, blending and storage), produced and flowback water services (gathering and disposal) and freshwater services (fracwater and flushwater supply and distribution) with Oasis Petroleum and its wholly-owned subsidiaries in the Williston Basin. At the same time, we became a party to the long-term, FERC-regulated transportation services agreement governing the transportation of crude oil via pipeline from the Wild Basin area to Johnson’s Corner. Also, in connection with the 2019 Delaware Acquisition, we entered into 15-year fixed fee contracts for crude oil services (gathering) and produced and flowback water services (gathering and disposal) with Oasis Petroleum and its wholly-owned subsidiaries in the Delaware Basin.

Oasis Petroleum’s retained interests. The Predecessor’s results of operations included 100% of the revenues and expenses associated with OMS prior to the initial public offering on September 25, 2017. At the closing of the initial public offering, OMS contributed to us equity interest in Bighorn DevCo, Bobcat DevCo and Beartooth DevCo. We consolidate the financial position and results of operations of our DevCos. As of December 31, 2019, Oasis Petroleum has retained interests in Bobcat DevCo and Beartooth DevCo, which are reflected as non-controlling interests in our consolidated financial statements. For further information on how we consolidate our DevCos, see Note 2 to our consolidated financial statements.

Excluded assets. Certain midstream infrastructure assets, liabilities, revenues and expenses included in the Predecessor’s historical financial statements have been excluded from the businesses of the DevCos.

G&A expenses. G&A expenses of the Predecessor and Delaware Predecessor included direct labor and indirect shared service expense allocations for support functions provided by Oasis Petroleum. Allocations were based primarily on headcount and direct usage during the respective periods of operations. We believe that these allocations were reasonable and reflected the utilization of services provided and benefits received, but may have differed from the cost that would have been incurred had we operated as a stand-alone entity. Under our Services and Secondment Agreement, Oasis Petroleum charges us a combination of direct and indirect allocated charges for G&A services.

Financing. Historically, the operations and capital expenditure requirements of the Predecessor and Delaware Predecessor were financed solely with capital contributions from Oasis Petroleum. The Predecessor and Delaware Predecessor recognized interest expense related to its funding activity with Oasis Petroleum based on capital expenditures for the period using the weighted average effective interest rate of Oasis Petroleum's long-term indebtedness.

In connection with the initial public offering, we entered into a credit agreement (the "Credit Agreement") for a revolving credit facility with OMP Operating LLC ("OMP Operating") as borrower (the "Revolving Credit Facility"). Borrowings under the Revolving Credit Facility bear interest at a rate per annum equal to the applicable margin (as described in the Credit Agreement) plus (i) with respect to Eurodollar Loans, the Adjusted LIBO Rate (as defined in the Credit Agreement) or (ii) with respect to ABR Loans, the greatest of (A) the Prime Rate in effect on such day, (B) the Federal Funds Effective Rate in effect on such day plus 1/2 of 1.00% or (C) the Adjusted LIBO Rate for a one-month interest period on such day plus 1.00% (each as defined in the Credit Agreement).

Income taxes. The Predecessor determined income tax expense and related deferred tax balance sheet accounts on a separate return method for the periods prior to the initial public offering. Following the closing of the initial public offering, we are treated as a partnership for U.S. federal income tax purposes and, therefore, generally are not liable for entity-level federal income taxes.

Results of Operations

Revenues

We categorize our revenues as either service revenues or product sales to the respective line items described below:

- *Midstream services - Oasis Petroleum.* We record service revenues for fee-based arrangements with Oasis Petroleum for midstream services, including: (i) natural gas gathering, compression, processing, gas lift and natural gas liquid ("NGL") storage services; (ii) crude oil gathering, stabilization, blending, storage and transportation services; and (iii) produced and flowback water gathering and disposal services.
- *Midstream services - third parties.* We record service revenues from third parties for crude oil gathering and produced and flowback water gathering and disposal services provided to non-affiliated customers.
- *Product sales - Oasis Petroleum.* We record product sales for the sale of residue gas and NGLs to certain subsidiaries of Oasis Petroleum, which we generate from third party natural gas purchase arrangements. We also record product sales for the supply and distribution of freshwater to Oasis Petroleum.
- *Product sales - third parties.* We record product sales from third parties for the supply and distribution of freshwater to non-affiliated customers.

The following table summarizes our revenues for the periods presented:

	Year Ended December 31,		
	2019(1)	2018(1)	2017
Operating results (in thousands):			
Revenues			
Midstream services – Oasis Petroleum	$ 317,072	$ 250,363	$ 168,205
Midstream services – third parties	6,531	2,604	1,973
Product sales – Oasis Petroleum	86,543	17,476	11,644
Product sales – third parties	45	3,327	394
Total revenues	$ 410,191	$ 273,770	$ 182,216

(1) Retrospectively adjusted for the transfer of net assets between entities under common control. See Note 4 to our consolidated financial statements.

Year ended December 31, 2019 as compared to year ended December 31, 2018

Total revenues increased $136.4 million to $410.2 million during the year ended December 31, 2019 as compared to the year ended December 31, 2018. This increase was driven by a $70.6 million increase in service revenues and a $65.8 million increase in product sales.

The increase in service revenues of $70.6 million was driven by a $58.8 million increase in natural gas service revenues due to an increase in natural gas volumes from Oasis Petroleum as a result of our second natural gas processing plant in Wild Basin coming online in the fourth quarter of 2018. In addition, there was an $8.2 million increase in produced and flowback water service revenues and a $3.6 million increase in crude oil service revenues due primarily to higher volumes from Oasis Petroleum in the Williston Basin and the Delaware Basin, coupled with the commencement of third party volumes in the Delaware Basin.

The increase in product sales of $65.8 million was driven by a $63.7 million increase in natural gas product sales, due to the commencement of third party natural gas purchase arrangements in the fourth quarter of 2018, coupled with a $2.1 million increase in freshwater product sales due primarily to an increase in fracwater deliveries to Oasis Petroleum in the Williston Basin.

Year ended December 31, 2018 as compared to year ended December 31, 2017

Total revenues increased $91.6 million to $273.8 million during the year ended December 31, 2018 as compared to the year ended December 31, 2017. This increase was driven by an $82.8 million increase in service revenues and an $8.8 million increase in product sales.

The increase in service revenues of $82.8 million was primarily due to a $49.4 million increase related to higher crude oil and natural gas service revenues and a $32.7 million increase in produced and flowback water service revenues, primarily as a result of increased production volumes from Oasis Petroleum.

The increase in product sales of $8.8 million was primarily due to a $4.0 million increase in freshwater product sales to Oasis Petroleum and a $3.3 million increase in freshwater product sales to third parties, coupled with a $1.4 million increase in natural gas product sales due to the commencement of third party natural gas purchase arrangements in the fourth quarter of 2018.

Expenses and other income

The following table summarizes our operating expenses and other income and expenses for the periods presented:

	Year Ended December 31,		
	2019[1]	2018[1]	2017
	(In thousands)		
Operating expenses			
Costs of product sales	$ 35,826	$ 7,433	$ 6,085
Operating and maintenance	74,226	63,685	39,441
Depreciation and amortization	36,358	28,409	15,730
General and administrative	31,009	23,897	18,597
Total operating expenses	177,419	123,424	79,853
Operating income	232,772	150,346	102,363
Other income (expense)			
Interest expense, net of capitalized interest	(17,538)	(2,580)	(6,965)
Other income (expense)	(3)	(14)	7
Total other expense, net	(17,541)	(2,594)	(6,958)
Income before income taxes	215,231	147,752	95,405
Income tax expense	—	—	(22,858)
Net income	215,231	147,752	72,547
Less: Net income prior to initial public offering	—	—	37,577
Less: Net income attributable to Delaware Predecessor	4,464	1,343	—
Less: Net income attributable to non-controlling interests	93,111	96,354	23,332
Net income attributable to OMP LP	117,656	50,055	11,638
Less: Net income attributable to General Partner	2,472	112	—
Net income attributable to limited partners	$ 115,184	$ 49,943	$ 11,638

(1) Retrospectively adjusted for the transfer of net assets between entities under common control. See Note 4 to our consolidated financial statements.

Year ended December 31, 2019 as compared to year ended December 31, 2018

Costs of product sales. The $28.4 million increase in costs of product sales for the year ended December 31, 2019 as compared to the year ended December 31, 2018 was primarily due a $28.0 million increase in costs of product sales related to third party natural gas purchase arrangements, which commenced in the fourth quarter of 2018.

Operating and maintenance. Operating and maintenance expenses increased $10.5 million to $74.2 million for the year ended December 31, 2019 as compared to the year ended December 31, 2018. This increase was primarily driven by a $8.7 million increase in natural gas operating and maintenance expenses due to our second natural gas processing plant in Wild Basin coming online in the fourth quarter of 2018. In addition, there was a $1.7 million increase in produced and flowback water operating and maintenance expenses due primarily to an increase in operating costs in the Delaware Basin as a result of increased activity.

Depreciation and amortization. Depreciation and amortization expense increased $7.9 million to $36.4 million for the year ended December 31, 2019 as compared to the year ended December 31, 2018 primarily as a result of additional assets placed into service during 2019.

General and administrative. G&A increased $7.1 million to $31.0 million for the year ended December 31, 2019 as compared to the year ended December 31, 2018. This increase was primarily a result of an increase in allocated charges from Oasis Petroleum for G&A services as a result of organizational growth in its midstream business segment.

Interest expense, net of capitalized interest. Interest expense, net of capitalized interest, increased $15.0 million to $17.5 million for the year ended December 31, 2019 as compared to December 31, 2018. This increase was primarily due to higher outstanding borrowings under our Revolving Credit Facility, coupled with a reduction in capitalized interest.

Year ended December 31, 2018 as compared to year ended December 31, 2017

Costs of product sales. The $1.3 million increase for the year ended December 31, 2018 as compared to the year ended December 31, 2017 was primarily due to the commencement of third party gas purchase arrangements in the fourth quarter of 2018.

Operating and maintenance. The $24.2 million increase for the year ended December 31, 2018 as compared to the year ended December 31, 2017 was primarily driven by a $15.8 million increase in crude oil and natural gas operating and maintenance costs due to higher volumes, coupled with a $8.5 million increase related to produced and flowback water operating and maintenance costs as a result of higher produced and flowback water service volumes in the Williston Basin.

Depreciation and amortization. Depreciation and amortization expense increased $12.7 million to $28.4 million for the year ended December 31, 2018 as compared to the year ended December 31, 2017, primarily as a result of additional assets placed into service in Wild Basin during 2018.

General and administrative. G&A increased $5.3 million to $23.9 million for the year ended December 31, 2018 as compared to the year ended December 31, 2017. This increase was primarily a result of public company expenses, including accounting and audit fees, legal fees, board and director expenses and equity-based compensation.

Interest expense, net of capitalized interest. Interest expense, net of capitalized interest, decreased $4.4 million to $2.6 million for the year ended December 31, 2018 as compared to December 31, 2017. This decrease was primarily due to higher capitalized interest in 2018, coupled with lower cash interest.

Income tax expense. The Partnership is not a taxable entity for U.S. federal income tax purposes and taxes are generally borne by our partners through the allocation of taxable income. Income tax expense for the year ended December 31, 2017 was recorded at 23.96% of pre-tax net income.

Liquidity and Capital Resources

Financing strategy

Our primary sources of liquidity are cash flows generated from operations primarily based on commercial agreements with Oasis Petroleum and borrowings under our Revolving Credit Facility. We believe cash generated from these sources will be sufficient to meet our short-term working capital needs, long-term capital expenditure requirements and quarterly cash distributions. As a result, we expect to fund future expansion capital expenditures and acquisitions primarily through a combination of borrowings under our Revolving Credit Facility and, if necessary, the issuance of additional equity or debt securities. Our primary uses of cash have been for capital expenditures for our midstream infrastructure, the acquisition of additional ownership interests in two of our DevCos, the acquisition of midstream infrastructure in the Delaware Basin from Oasis Petroleum, payment of direct operating costs, payment of general and administrative costs, interest payments on outstanding debt and payments of distributions to our partners. We expect our future cash requirements relating to working capital, maintenance capital expenditures and quarterly cash distributions to our unitholders will be funded from cash flows internally generated from our operations.

Cash flows

Our cash flows for the years ended December 31, 2019, 2018 and 2017 are presented below:

	Year Ended December 31,		
	2019[(1)]	2018[(1)]	2017
	(In thousands)		
Net cash provided by operating activities	$ 252,539	$ 206,344	$ 79,843
Net cash used in investing activities	(250,771)	(283,026)	(255,944)
Net cash provided by (used in) financing activities	(4,249)	82,448	176,984
Increase (decrease) in cash and cash equivalents	$ (2,481)	$ 5,766	$ 883

(1) Retrospectively adjusted for the transfer of net assets between entities under common control. See Note 4 to our consolidated financial statements.

Cash flows provided by operating activities

Net cash provided by operating activities was $252.5 million, $206.3 million and $79.8 million for the years ended December 31, 2019, 2018 and 2017, respectively. The increase in cash flows from operating activities for the year ended December 31, 2019 as compared to 2018 was primarily due to an increase in net income driven by higher revenues, partially offset by a decrease due to working capital changes. The increase in cash flows from operating activities for the year ended December 31, 2018 as compared to 2017 was primarily due to an increase in net income driven by higher revenues, coupled with an increase due to working capital changes.

Working capital. Our working capital fluctuates primarily as a result of changes in service volumes flowing through our systems and changes in accrued expenditures to operate our midstream infrastructure. As of December 31, 2019, we had a working capital balance of approximately $5.8 million. We believe we have adequate liquidity to meet our working capital requirements. As of December 31, 2019, we had $119.0 million of liquidity available, including $4.2 million in cash and cash equivalents and $114.8 million in unused borrowing capacity on the Revolving Credit Facility.

Cash flows used in investing activities

Net cash used in investing activities was $250.8 million, $283.0 million and $255.9 million for the years ended December 31, 2019, 2018 and 2017, respectively. The decrease in net cash used in investing activities for the year ended December 31, 2019 as compared to 2018 was primarily due to a decrease in expansion capital expenditures related to our second natural gas processing plant in Wild Basin, which was placed into service in the fourth quarter of 2018, partially offset by expansion capital expenditures related to the build out of our gathering system in the Delaware Basin.

The increase in net cash used in investing activities for the year ended December 31, 2018 as compared to 2017 was primarily due to an increase in expansion capital expenditures related to the construction of our second natural gas processing plant in Wild Basin, coupled with additional midstream gathering infrastructure in Wild Basin.

2019 Capital Expenditures Arrangement. On February 22, 2019, the Partnership entered into the MOU with Oasis Petroleum regarding the funding of Bobcat DevCo's capital expenditures for the 2019 calendar year, referred to as the 2019 Capital Expenditures Arrangement. Pursuant to the First A&R Bobcat LLCA, the Partnership and Oasis Petroleum were each required to make pro-rata capital contributions to Bobcat DevCo in accordance with their respective percentage ownership interests in Bobcat DevCo.

Pursuant to the MOU, the Partnership agreed to make up to $80.0 million of capital expenditures to Bobcat DevCo that Oasis Petroleum would otherwise be required to contribute under the First A&R Bobcat LLCA. In connection with execution of the MOU, the Partnership and Oasis Petroleum amended the First A&R Bobcat LLCA and entered into the Second A&R Bobcat LLCA. The Second A&R Bobcat LLCA includes provisions applicable to the disproportionate capital contributions that the Partnership will make to Bobcat DevCo in connection with the 2019 Capital Expenditures Arrangement. Pursuant to the Second A&R Bobcat LLCA, upon the occurrence of a disproportionate capital contribution, the Partnership's percentage interest and Oasis Petroleum's percentage interest in Bobcat DevCo will be adjusted to take into account the amount of the disproportionate capital contribution. During the year ended December 31, 2019, the Partnership made capital contributions to Bobcat DevCo pursuant to the 2019 Capital Expenditures Arrangement of $73.0 million. The Partnership's ownership interest in Bobcat DevCo increased from 25% as of December 31, 2018 to 35.3% as of December 31, 2019. The 2019 Capital Expenditures Arrangement ended on December 31, 2019 (see Note 5 to our consolidated financial statements).

Capital expenditures.

Our capital expenditures are summarized in the following table for the year ended December 31, 2019:

	Year Ended December 31, 2019	
	(In thousands)	
Capital expenditures	**Gross**	**Net**
Maintenance capital expenditures	$ 17,621	$ 8,346
Expansion capital expenditures	194,399	189,321
Capitalized interest	905	905
Total[(1)]	$ 212,925	$ 198,572

(1) Retrospectively adjusted for the transfer of net assets between entities under common control. Excludes $9.4 million of capital expenditures incurred in 2018 that were reimbursed to Oasis Petroleum on the effective date of November 1, 2019. Delaware Basin capital expenditures incurred in 2018 were recast to the 2018 consolidated financial statements in accordance with GAAP. See Note 4 to our consolidated financial statements.

Our capital expenditures by DevCo are summarized in the following table for the year ended December 31, 2019:

DevCo	OMP Ownership[3]	Year Ended December 31, 2019 (In thousands) Gross	Net
Bighorn DevCo	100%	$ 17,850	$ 17,850
Bobcat DevCo	35.3%	134,539	126,065
Beartooth DevCo	70%	19,596	13,717
Panther DevCo[2]	100%	40,035	40,035
OMP Operating	100%	905	905
Total[1]		$ 212,925	$ 198,572

(1) Capital expenditures reflected in the tables above differ from capital expenditures shown in the statement of cash flows in our consolidated financial statements because amounts reflected in the tables above include changes in accrued capital expenditures from the previous reporting period, while amounts presented in the statement of cash flows are presented on a cash basis.
(2) Retrospectively adjusted for the transfer of net assets between entities under common control. Excludes $9.4 million of capital expenditures incurred in 2018 that were reimbursed to Oasis Petroleum on the effective date of November 1, 2019. Delaware Basin capital expenditures incurred in 2018 were recast to the 2018 consolidated financial statements in accordance with GAAP. See Note 4 to our consolidated financial statements.
(3) Ownership interest as of December 31, 2019.

Our 2020 capital expenditures program, excluding acquisitions, will accommodate a gross capital expenditure level of approximately $110 million to $120 million, with approximately $68 million to $75 million attributable to the Partnership. We expect to spend approximately 6% to 8% of EBITDA for maintenance capital expenditures, which is included in our total capital expenditure program.

Cash flows provided by (used in) financing activities

For the year ended December 31, 2019, net cash used in financing activities was $4.2 million. This net use of cash was attributable to cash distributions to unitholders and non-controlling interests, offset by net borrowings on the Revolving Credit Facility and capital contributions from the Delaware Predecessor and non-controlling interests. For the years ended December 31, 2018 and 2017, net cash provided by financing activities was $82.4 million and $177.0 million, respectively. For the year ended December 31, 2018, net cash provided by financing activities was attributable to net borrowings on the Revolving Credit Facility, capital contributions from non-controlling interests and net proceeds from the public offering of our common units, partially offset by a cash distribution to Oasis Petroleum for the acquisition of additional ownership interests in Bobcat DevCo and Beartooth DevCo, cash distributions to non-controlling interests and cash distributions to unitholders.

For the year ended December 31, 2017, net cash provided by financing activities was primarily attributable to proceeds from our initial public offering, proceeds from borrowings on the Revolving Credit Facility and capital contributions from Oasis Petroleum prior to our initial public offering, offset by distributions to Oasis Petroleum.

Revolving credit facility. As of December 31, 2019, the Revolving Credit Facility had an aggregate commitment of $575.0 million. The Revolving Credit Facility is available to fund working capital and to finance acquisitions and other capital expenditures of the Partnership and matures on September 25, 2022.

On May 6, 2019, we entered into a second amendment to the Revolving Credit Facility to (i) increase the aggregate amount of commitments from $400.0 million to $475.0 million; (ii) provide for the ability to further increase commitments to $675.0 million; and (iii) add a new lender to the bank group. On August 16, 2019, we entered into a third amendment to the Revolving Credit Facility to (i) increase the aggregate amount of commitments from $475.0 million to $575.0 million and (ii) provide for the ability to further increase commitments to $775.0 million.

Principal amounts borrowed are payable on the maturity date and interest is payable quarterly for ABR Loans (as defined in the Credit Agreement) and at the end of the applicable interest period for Eurodollar Loans (as defined in the Credit Agreement), and with respect to Eurodollar Borrowings with an interest period of more than three months duration, at each three month interval. Borrowings under the Revolving Credit Facility bear interest at a rate per annum equal to the applicable margin (as described below) plus (i) with respect to Eurodollar Loans, the Adjusted LIBO Rate (as defined in the Credit Agreement) or

(ii) with respect to ABR Loans, the greatest of (A) the Prime Rate in effect on such day, (B) the Federal Funds Effective Rate in effect on such day plus 1/2 of 1.00% or (C) the Adjusted LIBO Rate for a one-month interest period on such day plus 1.00% (each as defined in the Credit Agreement). The applicable margin for borrowings under the Revolving Credit Facility is based on the Partnership's most recently tested consolidated total leverage ratio and varies from (a) in the case of Eurodollar Loans, 1.75% to 2.75%, and (b) in the case of ABR Loans or swingline loans, 0.75% to 1.75%. The unused portion of the Revolving Credit Facility is subject to a commitment fee ranging from 0.375% to 0.50%.

The Revolving Credit Facility is secured by mortgages and other security interests on substantially all of the Partnership's and its subsidiaries' properties and assets, including the equity interests in all present and future subsidiaries (subject to certain exceptions).

The Revolving Credit Facility provides for customary representations, warranties and covenants, including, among other things, covenants relating to financial and collateral reporting, notices of material events, maintenance of the existence of the business and its properties, payment of obligations, the Partnership's ability to enter into certain hedging agreements, limitations on the Partnership's ability to sell or acquire properties and limitations on indebtedness and liens, dividends and distributions, transactions with affiliates and certain fundamental transactions.

The Revolving Credit Facility also requires the Partnership to maintain the following financial covenants (which are described in more detail in the Credit Agreement):

- Consolidated Total Leverage Ratio: Prior to the date on which one or more of the credit parties have issued an aggregate principal amount of at least $150.0 million of senior notes (as permitted under the Revolving Credit Facility) (such date the "Covenant Changeover Date") and commencing with the fiscal quarter ended December 31, 2017, the Partnership and OMP Operating's ratio of Total Debt to EBITDA (each as defined in the Credit Agreement) on a quarterly basis may not exceed 4.50 to 1.00 (or during an Acquisition Period (as defined in the Credit Agreement), 5.00 to 1.00). On a quarterly basis following the Covenant Changeover Date, the Partnership and OMP Operating's ratio of Total Debt to EBITDA may not exceed 5.25 to 1.00.
- Consolidated Senior Secured Leverage Ratio: On a quarterly basis following the Covenant Changeover Date, the Partnership and OMP Operating's ratio of Consolidated Senior Secured Funded Debt to EBITDA (each as defined in the Credit Agreement) may not exceed 3.75 to 1.00.
- Consolidated Interest Coverage Ratio: On a quarterly basis prior to the Covenant Changeover Date and commencing with the fiscal quarter ended December 31, 2017, the Partnership and OMP Operating's ratio of EBITDA to Consolidated Interest Expense (each as defined in the Credit Agreement) may not be less than 3.00 to 1.00 and on a quarterly basis following the Covenant Changeover Date, the Partnership and OMP Operating's ratio of EBITDA to Consolidated Interest Expense may not be less than 2.50 to 1.00.

The Partnership was in compliance with the financial covenants of the Revolving Credit Facility as of December 31, 2019.

Cash distributions

Our partnership agreement requires that all of the Partnership's available cash be distributed quarterly. Under the current cash distribution policy, the Partnership intends to distribute to the holders of common and subordinated units on a quarterly basis at least the minimum quarterly distribution of $0.3750 per unit, or $1.50 on an annualized basis, to the extent the Partnership has sufficient cash after establishment of cash reserves and payment of fees and expenses, including payments to the General Partner and its affiliates.

On January 30, 2020, the board of directors of the General Partner declared the quarterly distribution for the fourth quarter of $0.54 per unit. In addition, the General Partner will receive a cash distribution of $1.0 million attributable to its IDRs related to earnings for the fourth quarter. These distributions will be paid on February 27, 2020 to unitholders of record as of February 13, 2020.

Obligations and commitments

We have the following gross contractual obligations and commitments as of December 31, 2019:

	Payments due by period				
	Total	Within 1 year	1-3 years	3-5 years	More than 5 years
			(In thousands)		
Borrowings under Revolving Credit Facility[1]	$ 458,500	$ —	$ 458,500	$ —	$ —
Interest payments on borrowings under Revolving Credit Facility[1]	508	508	—	—	—
Asset retirement obligations[2]	1,747	—	—	—	1,747
Finances leases[3]	830	11	90	90	639
Operating leases[3]	5,423	3,150	2,273	—	—
Volume commitment agreements [4]	8,073	3,600	3,635	—	838
Total contractual cash obligations	$ 475,081	$ 7,269	$ 464,498	$ 90	$ 3,224

(1) See Note 8 to our consolidated financial statements for a description of the Revolving Credit Facility and related interest payments.
(2) Amounts represent the present value of estimated costs expected to be incurred in the future to plug, abandon and remediate our produced and flowback water disposal wells at the end of their productive lives. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions. See Note 2 to our consolidated financial statements.
(3) See Note 9 to our consolidated financial statements for a description of our leases.
(4) See Note 11 to our consolidated financial statements for a description of our volume commitment agreements.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. We provide expanded discussion of our more significant accounting policies, estimates and judgments used in preparation of our financial statements below. See Note 2 to our consolidated financial statements for a discussion of the significant accounting policies and estimates made by management.

Property, plant and equipment

Property, plant and equipment is stated at the lower of historical cost less accumulated depreciation, or fair value, if impaired. Expenditures which extend the useful life of property, plant and equipment, maintain the long-term system operating capacity of our assets, or increase system throughput or capacity from current levels are capitalized. Our capital expenditure requirements are categorized as either:

Maintenance capital expenditures, which are cash expenditures (including expenditures for the construction or development of new capital assets or the replacement, improvement or expansion of existing capital assets) made to maintain, over the long term, system operating capacity, operating income or revenue. Examples of maintenance capital expenditures are expenditures to repair, refurbish and replace pipelines, to maintain equipment reliability, integrity and safety and to comply with environmental laws and regulations. In addition, we designate a portion of our capital expenditures to connect new wells to maintain gathering throughput as maintenance capital expenditures to the extent such capital expenditures are necessary to maintain, over the long term, system operating capacity, operating income or revenue. Cash expenditures made solely for investment purposes will not be considered maintenance capital expenditures; or

Expansion capital expenditures, which are cash expenditures to acquire additional interests in our midstream assets and to construct new midstream infrastructure and those expenditures incurred in order to extend the useful lives of our assets, reduce costs, increase revenues or increase system throughput or capacity from current levels, including well connections that increase existing system operating capacity, operating income or revenue. Examples of expansion capital expenditures include the acquisition of additional interests in our DevCos, and the construction, development or acquisition of additional midstream assets, in each case, to the extent such capital expenditures are expected to increase, over the long term, system operating capacity, operating income or revenue. In the future, if we make acquisitions that increase system operating capacity, operating income or revenue, the associated capital expenditures may also be considered expansion capital expenditures.

When assets are placed into service, management makes estimates with respect to useful lives and salvage values that management believes are reasonable. However, subsequent events could cause a change in estimates, thereby impacting future depreciation amounts. Uncertainties that may impact these estimates include, among others, changes in laws and regulations relating to environmental matters, including air and water quality, restoration and abandonment requirements, economic conditions and supply and demand in the area. Depreciation is computed over the asset's estimated useful life using the straight line method based on estimated useful lives and asset salvage values. The weighted average life of our long-lived assets is 30 years. When properties are retired or otherwise disposed of, the related cost and accumulated depreciation are removed from the respective accounts and any profit or loss on disposition is recognized as gain or loss.

Impairment of long-lived assets

We evaluate the ability to recover the carrying amount of long-lived assets and determine whether such long-lived assets have been impaired. Impairment exists when the carrying amount of an asset exceeds estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. Our impairment analysis requires management to apply judgment in identifying impairment indicators and estimating future cash flows. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, estimates of future undiscounted cash flows take into account possible outcomes and probabilities of their occurrence. If the carrying amount of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, the impairment loss is measured as the excess of the asset's carrying amount over its estimated fair value, such that the asset's carrying amount is adjusted to its estimated fair value with an offsetting charge to impairment expense.

Fair value represents the estimated price between market participants to sell an asset in the principal or most advantageous market for the asset, based on assumptions a market participant would make. When warranted, management assesses the fair value of long-lived assets using commonly accepted techniques and may use more than one source in making such assessments. The factors used to determine fair value are subject to management's judgment and expertise and include, but are not limited to, recent third-party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors. Significant changes, such as changes in contract rates or terms, the condition of an asset or management's intent to utilize the asset, generally require management to reassess the cash flows related to long-lived assets. A reduction of the carrying value of fixed assets would represent a Level 3 fair value measurement.

If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to additional impairment charges. Ultimately, a prolonged period of lower commodity prices may adversely affect our estimate of future operating results through lower throughput volumes on our assets, which could result in future impairment charges due to the potential impact on our operations and cash flows.

Asset retirement obligations

We record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred, with the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. For disposal wells, this is the period in which the well is drilled or acquired. The asset retirement obligation ("ARO") represents the estimated amount we will incur to plug, abandon and remediate the produced and flowback water properties at the end of their useful lives, in accordance with applicable state laws. The liability is accreted to its present value each period and the capitalized costs are depreciated using the straight-line method. The accretion expense is recorded as a component of depreciation and amortization in our Consolidated Statements of Operations.

Some of our assets, including certain pipelines and our natural gas processing plants, have contractual or regulatory obligations to perform remediation and, in some instances, dismantlement and removal activities when the assets are abandoned. We are not able to reasonably estimate the fair value of the ARO for these assets because the settlement dates are indeterminable given the expected continued use of the assets with proper maintenance. We will record an ARO for these assets in the periods in which the settlement dates become reasonably determinable.

We determine the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

General and administrative expenses

We are party to a 15-year Services and Secondment Agreement with Oasis Petroleum, pursuant to which Oasis Petroleum performs certain G&A services. In addition, Oasis Petroleum has seconded to us certain of its employees to operate, construct, manage and maintain our assets. The Services and Secondment Agreement requires us to reimburse Oasis Petroleum for direct G&A expenses incurred for the provision of these services.

We determine the allocated G&A expenses performed under the Services and Secondment Agreement using certain estimates and assumptions of the expense attributable to our operations. Management believes these estimates and assumptions are reasonable.

Recent Accounting Pronouncements

See Note 2 to our consolidated financial statements for a description of the effect of recent accounting pronouncements on our consolidated financial statements.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2019, 2018 and 2017. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy, and in the past, we have tended to experience inflationary pressure on the cost to acquire, build or replace property, plant and equipment.

Off-balance sheet arrangements

Currently, we do not have any off-balance sheet arrangements as defined by the SEC. In the ordinary course of business, we enter into various commitment agreements and other contractual obligations, some of which are not recognized in our consolidated financial statements in accordance with GAAP. See “Obligations and commitments” above and Note 11 to our consolidated financial statements for a description of our commitments and contingencies.

Non-GAAP Financial Measures

Cash Interest, Adjusted EBITDA and Distributable Cash Flow are supplemental non-GAAP financial measures that are used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. These non-GAAP financial measures should not be considered in isolation or as a substitute for interest expense, net income (loss), operating income (loss), net cash provided by (used in) operating activities or any other measures prepared under GAAP. Because Cash Interest, Adjusted EBITDA and Distributable Cash Flow exclude some but not all items that affect interest expense, net income and net cash provided by operating activities and may vary among companies, the amounts presented may not be comparable to similar metrics of other companies.

Cash Interest

We define Cash Interest as interest expense plus capitalized interest less amortization of deferred financing costs included in interest expense. Cash Interest is not a measure of interest expense as determined by GAAP. Management believes that the presentation of Cash Interest provides useful additional information to investors and analysts for assessing the interest charges incurred on our debt, excluding non-cash amortization, and our ability to maintain compliance with our debt covenants.

The following table presents a reconciliation of the GAAP financial measure of interest expense to the non-GAAP financial measure of Cash Interest for the periods presented:

	Year Ended December 31,		
	2019[1]	**2018[1]**	**2017**
		(In thousands)	
Interest expense, net of capitalized interest	$ 17,538	$ 2,580	$ 6,965
Capitalized interest[2]	905	4,870	1,220
Amortization of deferred financing costs	(946)	(525)	(126)
Cash Interest	**$ 17,497**	**$ 6,925**	**$ 8,059**
Less: Cash Interest prior to the initial public offering	—	—	7,603
Less: Cash Interest attributable to Delaware Predecessor	(813)	(237)	—
Less: Cash Interest attributable to non-controlling interests	(11)	—	—
Cash Interest attributable to Oasis Midstream Partners LP	**$ 16,673**	**$ 6,688**	**$ 456**

(1) Retrospectively adjusted for the transfer of net assets between entities under common control. See Note 4 to our consolidated financial statements.
(2) Capitalized interest allocated to the Predecessor prior to the initial public offering was $0.7 million
for the year ended December 31, 2017. The Partnership recorded capitalized interest on borrowings under the Revolving Credit Facility of $0.6 million for the year ended December 31, 2017. See Note 8 to our consolidated financial statements for a description of our long-term debt.

Adjusted EBITDA

We define Adjusted EBITDA as earnings before interest expense (net of capitalized interest), income taxes, depreciation, amortization, equity-based compensation expenses and other similar non-cash adjustments. We define Adjusted EBITDA attributable to Oasis Midstream Partners LP as Adjusted EBITDA less Adjusted EBITDA attributable to Oasis Petroleum's retained interests in two of our DevCos. Adjusted EBITDA should not be considered an alternative to net income, net cash provided by operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Management believes that the presentation of Adjusted EBITDA provides information useful to investors and analysts for assessing our results of operations, financial performance and our ability to generate cash from our business operations without regard to our financing methods or capital structure coupled with our ability to maintain compliance with our debt covenants. The GAAP measures most directly comparable to Adjusted EBITDA are net income and net cash provided by operating activities.

Distributable Cash Flow

We define Distributable Cash Flow as Adjusted EBITDA attributable to Oasis Midstream Partners LP less Cash Interest and maintenance capital expenditures attributable to Oasis Midstream Partners LP. Distributable Cash Flow should not be considered an alternative to net income, net cash provided by operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Management believes that the presentation of Distributable Cash Flow provides information useful to investors and analysts for assessing our results of operations, financial performance and our ability to generate cash from our business operations without regard to our financing methods or capital structure, coupled with our ability to make distributions to our unitholders. The GAAP measures most directly comparable to Distributable Cash Flow are net income and net cash provided by operating activities.

The following table presents reconciliations of the GAAP financial measures of net income and net cash provided by operating activities to the non-GAAP financial measure of Adjusted EBITDA and Distributable Cash Flow for the periods presented:

	Year Ended December 31,		
	2019[1]	2018[1]	2017
		(In thousands)	
Net income	$ 215,231	$ 147,752	$ 72,547
Income tax expense	—	—	22,858
Depreciation and amortization	36,358	28,409	15,730
Equity-based compensation expenses	378	356	1,052
Interest expense, net of capitalized interest	17,538	2,580	6,965
Adjusted EBITDA	**$ 269,505**	**$ 179,097**	**$ 119,152**
Less: Adjusted EBITDA prior to the initial public offering	—	—	79,484
Less: Adjusted EBITDA attributable to Delaware Predecessor	5,510	1,585	—
Less: Adjusted EBITDA attributable to non-controlling interests	105,053	108,754	25,955
Adjusted EBITDA attributable to OMP LP	**$ 158,942**	**$ 68,758**	**$ 13,713**
Cash Interest attributable to OMP LP	16,673	6,688	456
Maintenance capital expenditures attributable to OMP LP	8,346	2,747	1,183
Distributable Cash Flow attributable to OMP LP	**$ 133,923**	**$ 59,323**	**$ 12,074**
Net cash provided by operating activities	$ 252,539	$ 206,344	$ 79,843
Current tax expense	—	—	17,618
Interest expense, net of capitalized interest	17,538	2,580	6,965
Changes in working capital	374	(30,346)	14,853
Other non-cash adjustments	(946)	519	(127)
Adjusted EBITDA	**$ 269,505**	**$ 179,097**	**$ 119,152**
Less: Adjusted EBITDA prior to the initial public offering	—	—	79,484
Less: Adjusted EBITDA attributable to Delaware Predecessor	5,510	1,585	—
Less: Adjusted EBITDA attributable to non-controlling interests	105,053	108,754	25,955
Adjusted EBITDA attributable to OMP LP	**$ 158,942**	**$ 68,758**	**$ 13,713**
Cash Interest attributable to OMP LP	16,673	6,688	456
Maintenance capital expenditures attributable to OMP LP	8,346	2,747	1,183
Distributable Cash Flow attributable to OMP LP	**$ 133,923**	**$ 59,323**	**$ 12,074**

(1) Retrospectively adjusted for the transfer of net assets between entities under common control. See Note 4 to our consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term “market risk” refers to the risk of loss arising from adverse changes in commodity prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures.

Customer credit risk. We are dependent on Oasis Petroleum as our most significant customer, and we expect to derive a substantial majority of our revenues from Oasis Petroleum for the foreseeable future. As a result, any event, whether in our dedicated areas or otherwise, that adversely affects Oasis Petroleum’s production, drilling schedule, financial condition, leverage, market reputation, liquidity, results of operations or cash flows may adversely affect our revenues and cash available for distribution. Further, we are subject to the risk of non-payment or non-performance by Oasis Petroleum. We cannot predict the extent to which Oasis Petroleum’s business would be impacted if conditions in the energy industry were to deteriorate, nor can we estimate the impact such conditions would have on Oasis Petroleum’s ability to execute its drilling and development program or to perform under our agreements. Any material non-payment or non-performance by Oasis Petroleum could reduce our ability to make distributions to our unitholders. We did not experience any significant defaults on accounts receivable for the years ended December 31, 2019, 2018 and 2017.

Commodity price risk. We have limited direct exposure to risks associated with fluctuating commodity prices due to the nature of our business and our commercial arrangements with Oasis Petroleum and third parties. However, to the extent that our future contractual arrangements with Oasis Petroleum or third parties do not provide for fixed-fee structures, we may become subject to commodity price risk. Additionally, as substantially all of our revenues are derived from Oasis Petroleum, we will be indirectly subject to risks associated with fluctuating commodity prices to the extent that lower commodity prices adversely affect Oasis Petroleum’s production, drilling schedule, financial condition, leverage, market reputation, liquidity, results of operations or cash flows.

Interest rate risk. At December 31, 2019, we had $458.5 million of borrowings outstanding under our Revolving Credit Facility with an aggregate commitment amount of $575.0 million. Borrowings under the Revolving Credit Facility bear interest at a rate per annum equal to the applicable margin (as described below) plus (i) with respect to Eurodollar Loans, the Adjusted LIBO Rate (as defined in the Credit Agreement) or (ii) with respect to ABR Loans, the greatest of (A) the Prime Rate in effect on such day, (B) the Federal Funds Effective Rate in effect on such day plus 1/2 of 1.00% or (c) the Adjusted LIBO Rate for a one-month interest period on such day plus 1.00% (each as defined in the Credit Agreement). The applicable margin for borrowings under the Revolving Credit Facility is based on the Partnership’s most recently tested consolidated total leverage ratio and varies from (a) in the case of Eurodollar Loans, 1.75% to 2.75%, and (b) in the case of ABR Loans or swingline loans, 0.75% to 1.75%. The unused portion of the Revolving Credit Facility is subject to a commitment fee ranging from 0.375% to 0.50%.

At December 31, 2019, the outstanding borrowings under our Revolving Credit Facility bore interest at LIBOR plus a 2.00% margin. We do not currently, but may in the future, utilize interest rate derivatives to mitigate interest rate exposure in efforts to reduce interest rate expense related to debt issued under our Revolving Credit Facility. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Item 8. Financial Statements and Supplementary Data

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Report of Independent Registered Public Accounting Firm

To the Board of Directors of OMP GP LLC and Unitholders of Oasis Midstream Partners LP

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Oasis Midstream Partners LP and its subsidiaries (the "Partnership") as of December 31, 2019 and 2018, and the related consolidated statements of operations, changes in equity, and cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Significant Transactions with Related Parties

As discussed in Note 5 to the consolidated financial statements, the Partnership has entered into significant transactions with Oasis Petroleum Inc. and Oasis Petroleum North America LLC, related parties.

/s/PricewaterhouseCoopers LLP

Houston, Texas

February 26, 2020

We have served as the Partnership's auditor since 2017.

OASIS MIDSTREAM PARTNERS LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2019	December 31, 2018[1]
	(In thousands, except unit data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 4,168	$ 6,649
Accounts receivable	5,969	2,481
Accounts receivable – Oasis Petroleum	77,571	81,022
Prepaid expenses	1,923	1,418
Other current assets	138	22
Total current assets	89,769	91,592
Property, plant and equipment	1,155,503	942,578
Less: accumulated depreciation and amortization	(98,982)	(62,730)
Total property, plant and equipment, net	1,056,521	879,848
Operating lease right-of-use assets	5,207	—
Other assets	3,172	2,452
Total assets	$ 1,154,669	$ 973,892
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable	$ 2,478	$ 2,180
Accounts payable – Oasis Petroleum	27,139	33,014
Accrued liabilities	50,210	60,954
Accrued interest payable	508	442
Current operating lease liabilities	3,005	—
Other current liabilities	594	—
Total current liabilities	83,934	96,590
Long-term debt	458,500	318,000
Asset retirement obligations	1,747	1,630
Operating lease liabilities	2,216	—
Other liabilities	3,644	—
Total liabilities	550,041	416,220
Commitments and contingencies (Note 11)		
Equity		
Limited partners		
Common units (20,045,196 and 20,029,026 issued and outstanding at December 31, 2019 and December 31, 2018, respectively)	225,339	192,581
Subordinated units (13,750,000 units issued and outstanding at December 31, 2019 and December 31, 2018)	66,005	45,937
General Partner	1,026	112
Total partners' equity	292,370	238,630
Non-controlling interests	312,258	312,815
Delaware Predecessor	—	6,227
Total equity	604,628	557,672
Total liabilities and equity	$ 1,154,669	$ 973,892

(1) Retrospectively adjusted for the transfer of net assets between entities under common control. See Note 4 — Acquisitions.

The accompanying notes are an integral part of these consolidated financial statements.

OASIS MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2019[(1)]	2018[(1)]	2017
	(In thousands, except per unit data)		
Revenues			
Midstream services – Oasis Petroleum	$ 317,072	$ 250,363	$ 168,205
Midstream services – third parties	6,531	2,604	1,973
Product sales – Oasis Petroleum	86,543	17,476	11,644
Product sales – third parties	45	3,327	394
Total revenues	410,191	273,770	182,216
Operating expenses			
Costs of product sales	35,826	7,433	6,085
Operating and maintenance	74,226	63,685	39,441
Depreciation and amortization	36,358	28,409	15,730
General and administrative	31,009	23,897	18,597
Total operating expenses	177,419	123,424	79,853
Operating income	232,772	150,346	102,363
Other income (expense)			
Interest expense, net of capitalized interest	(17,538)	(2,580)	(6,965)
Other income (expense)	(3)	(14)	7
Total other expense, net	(17,541)	(2,594)	(6,958)
Income before income taxes	215,231	147,752	95,405
Income tax expense	—	—	(22,858)
Net income	215,231	147,752	72,547
Less: Net income prior to initial public offering	—	—	37,577
Less: Net income attributable to Delaware Predecessor	4,464	1,343	—
Less: Net income attributable to non-controlling interests	93,111	96,354	23,332
Net income attributable to OMP LP	117,656	50,055	11,638
Less: Net income attributable to General Partner	2,472	112	—
Net income attributable to limited partners	$ 115,184	$ 49,943	$ 11,638
Earnings per limited partner unit (Note 14)			
Common units – basic and diluted	$ 3.41	$ 1.82	$ 0.43
Weighted average number of limited partners units outstanding (Note 14)			
Common units – basic	20,024	14,504	13,566
Common units – diluted	20,032	14,519	13,568

(1) Retrospectively adjusted for the transfer of net assets between entities under common control. See Note 4 — Acquisitions.

The accompanying notes are an integral part of these consolidated financial statements.

OASIS MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

			Partnership				
	Predecessor	Delaware Predecessor	Common units	Subordinated units	General Partner	Non-controlling interests	Total equity
				(In thousands)			
Balance as of December 31, 2016	$ 331,675	$ —	$ —	$ —	$ —	$ —	$ 331,675
Cumulative effect adjustment for adoption of ASU 2016-09	(59)	—	—	—	—	—	(59)
Equity-based compensation	999	—	—	—	—	—	999
Capital contributions prior to initial public offering	65,145	—	—	—	—	—	65,145
Net income prior to initial public offering	37,577	—	—	—	—	—	37,577
Balance as of September 25, 2017	435,337	—	—	—	—	—	435,337
Elimination of current and deferred tax liabilities	104,005	—	—	—	—	—	104,005
Net assets excluded from initial public offering	(50,726)	—	—	—	—	—	(50,726)
Allocation of net investment to unitholders	(488,616)	—	53,704	144,077	—	290,835	—
Net proceeds from initial public offering	—	—	134,185	—	—	—	134,185
Proceeds from initial public offering distributed to Oasis Petroleum	—	—	(26,360)	(70,723)	—	(35,000)	(132,083)
Contributions from non-controlling interests	—	—	—	—	—	34,279	34,279
Equity-based compensation	—	—	53	—	—	—	53
Net income subsequent to initial public offering	—	—	5,819	5,819	—	23,332	34,970
Balance as of December 31, 2017	—	—	167,401	79,173	—	313,446	560,020
Delaware Predecessor capital contributions, net	—	4,884	—	—	—	—	4,884
Contributions from non-controlling interests	—	—	—	—	—	147,453	147,453
Distributions to non-controlling interests	—	—	—	—	—	(128,903)	(128,903)
Distributions to unitholders	—	—	(22,478)	(22,440)	—	—	(44,918)
2018 Dropdown Acquisition	—	—	45,935	69,600	—	(115,535)	—
Distribution to Oasis Petroleum for 2018 Dropdown Acquisition	—	—	(68,556)	(103,873)	—	—	(172,429)
Issuance of common units	—	—	44,503	—	—	—	44,503
Equity-based compensation	—	—	356	—	—	—	356
Other	—	—	(493)	(553)	—	—	(1,046)
Net income	—	1,343	25,913	24,030	112	96,354	147,752
Balance as of December 31, 2018	—	6,227	192,581	45,937	112	312,815	557,672
Delaware Predecessor capital contributions, net	—	14,008	—	—	—	—	14,008
Contributions from non-controlling interests	—	—	—	—	—	5,078	5,078
Distributions to non-controlling interests	—	—	—	—	—	(95,771)	(95,771)
Distributions to unitholders	—	—	(38,587)	(26,469)	(1,558)	—	(66,614)
Equity-based compensation	—	—	378	—	—	—	378
2019 Delaware Acquisition	—	(24,699)	(95)	(145)	—	—	(24,939)
Other	—	—	2,771	(211)	—	(2,975)	(415)
Net income	—	4,464	68,291	46,893	2,472	93,111	215,231
Balance as of December 31, 2019	$ —	$ —	$ 225,339	$ 66,005	$ 1,026	$ 312,258	$ 604,628

The accompanying notes are an integral part of these consolidated financial statements.

OASIS MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2019[(1)]	2018[(1)]	2017
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 215,231	$ 147,752	$ 72,547
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	36,358	28,409	15,730
Deferred income taxes	—	—	5,240
Equity-based compensation expenses	378	356	1,052
Deferred financing costs amortization and other	946	(519)	127
Working capital and other changes:			
Change in accounts receivable	(37)	3,194	(56,473)
Change in prepaid expenses	(505)	(640)	(304)
Change in accounts payable and accrued liabilities	(3,311)	27,814	24,400
Change in current income taxes payable	—	—	17,618
Change in other assets and liabilities, net	3,479	(22)	(94)
Net cash provided by operating activities	252,539	206,344	79,843
Cash flows from investing activities:			
Capital expenditures	(225,832)	(283,026)	(181,424)
Acquisitions	(24,939)	—	(74,520)
Net cash used in investing activities	(250,771)	(283,026)	(255,944)
Cash flows from financing activities:			
Capital contributions from parent prior to initial public offering	—	—	65,145
Capital contributions from non-controlling interests	5,078	140,277	33,875
Capital contributions from Delaware Predecessor, net	14,008	4,884	—
Proceeds from initial public offering, net of offering costs	—	—	134,185
Proceeds from sale of common units, net of offering costs	—	44,503	—
Distribution to Oasis Petroleum subsequent to initial public offering	—	—	(132,083)
Distributions to non-controlling interests	(95,771)	(128,903)	—
Distribution to Oasis Petroleum for contributed assets	—	(172,429)	—
Distributions to unitholders	(66,615)	(44,918)	—
Deferred financing costs	(973)	(966)	(2,138)
Proceeds from revolving credit facility	153,000	275,000	78,000
Principal payments on revolving credit facility	(12,500)	(35,000)	—
Other	(476)	—	—
Net cash provided by (used in) financing activities	(4,249)	82,448	176,984
Increase (decrease) in cash and cash equivalents	(2,481)	5,766	883
Cash:			
Beginning of period	6,649	883	—
End of period	$ 4,168	$ 6,649	$ 883
Supplemental cash flow information:			
Cash paid for interest, net of capitalized interest	$ 16,592	$ 2,054	$ —
Supplemental non-cash transactions:			
Change in accrued capital expenditures	$ (12,945)	$ (1,794)	$ 63,199
Change in asset retirement obligations	117	314	198
Installment notes from acquisition	—	—	4,875
Reimbursement of capital expenditures from Oasis Petroleum	—	7,176	—
Non-cash elimination of current and deferred tax liabilities	—	—	104,005

(1) Retrospectively adjusted for the transfer of net assets between entities under common control. See Note 4 — Acquisitions.

The accompanying notes are an integral part of these consolidated financial statements.

1. Organization and Nature of Operations

Organization. Oasis Midstream Partners LP (the “Partnership”) is a growth-oriented, fee-based master limited partnership formed by its sponsor, Oasis Petroleum Inc. (together with its subsidiaries, “Oasis Petroleum”) to own, develop, operate and acquire a diversified portfolio of midstream assets in North America that are integral to the crude oil and natural gas operations of Oasis Petroleum and are strategically positioned to capture volumes from other producers.

The Partnership conducts its business through its ownership of the following development companies: Bighorn DevCo LLC (“Bighorn DevCo”), Bobcat DevCo LLC (“Bobcat DevCo”), Beartooth DevCo LLC (“Beartooth DevCo”) and Panther DevCo LLC (“Panther DevCo” and collectively with Bighorn DevCo, Bobcat DevCo and Beartooth DevCo, the “DevCos”), two of which are jointly-owned with Oasis Petroleum.

Initial public offering. The Partnership completed its initial public offering in 2017. In connection with the Partnership’s initial public offering, Oasis Petroleum contributed to the Partnership a 100% ownership interest in Bighorn DevCo, a 10% ownership interest in Bobcat DevCo and a 40% ownership interest in Beartooth DevCo.

2018 Dropdown Acquisition. On November 19, 2018, the Partnership acquired an additional 15% ownership interest in Bobcat DevCo and an additional 30% ownership interest in Beartooth DevCo. See Note 4 — Acquisitions.

2019 Capital Expenditures Arrangement. On February 22, 2019, the Partnership entered into the 2019 Capital Expenditures Arrangement (defined below) pursuant to which the Partnership agreed to pay up to $80.0 million of expansion capital expenditures associated with Oasis Petroleum’s retained interest in Bobcat DevCo, in exchange for increasing ownership interest in Bobcat DevCo. During the year ended December 31, 2019, the Partnership made capital contributions to Bobcat DevCo pursuant to the 2019 Capital Expenditures Arrangement of $73.0 million. As a result, the Partnership’s ownership interest in Bobcat DevCo increased from 25% as of December 31, 2018 to 35.3% as of December 31, 2019. The 2019 Capital Expenditures Arrangement ended on December 31, 2019. See Note 5 — Transactions with Affiliates.

2019 Delaware Acquisition. On November 1, 2019, the Partnership entered into an agreement with Oasis Petroleum, pursuant to which Oasis Petroleum agreed to assign to Panther DevCo, a wholly-owned subsidiary of the Partnership, certain crude oil gathering and produced and flowback water gathering and disposal assets in the Delaware Basin (the “2019 Delaware Acquisition”). See Note 4 — Acquisitions.

As of December 31, 2019, the Partnership’s assets and ownership interests in the DevCos were as follows:

DevCos	Areas Served	Service Lines	OMP Ownership
Bighorn DevCo	Wild Basin	– Natural gas processing – Crude oil stabilization – Crude oil blending – Crude oil and NGL storage – Crude oil transportation	100%
Bobcat DevCo	Wild Basin	– Natural gas gathering – Natural gas compression – Gas lift – Crude oil gathering – Produced and flowback water gathering – Produced and flowback water disposal	35.3%
Beartooth DevCo	Alger Cottonwood Hebron Indian Hills Red Bank Wild Basin	– Produced and flowback water gathering – Produced and flowback water disposal – Freshwater supply and distribution	70%
Panther DevCo	Delaware Basin	– Crude oil gathering – Produced and flowback water gathering – Produced and flowback water disposal	100%

2. Summary of Significant Accounting Policies and Basis of Presentation

Basis of Presentation

The accompanying consolidated financial statements of the Partnership include the accounts of Oasis Midstream Partners LP and its subsidiaries. All intercompany transactions have been eliminated in consolidation. These statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP").

The 2019 Delaware Acquisition was accounted for as a transfer of net assets between entities under common control (see Note 4 — Acquisitions). As a result, the Partnership recorded the net assets acquired at historic carrying value and recast its financial statements to include such net assets from the date of common control. The Partnership recast its consolidated financial statements as of and for the year ended December 31, 2018, and prior to the effective date of November 1, 2019 for the year ended December 31, 2019. The consolidated financial statements for the year ended December 31, 2017 were not recast, since Oasis Petroleum first entered the Delaware Basin in 2018 following its acquisition of certain assets from Forge Energy, LLC.

For those periods requiring recast, the consolidated financial statements for periods prior to the effective date were prepared from Oasis Petroleum's historical cost-basis accounts and may not necessarily be indicative of the actual results had the Partnership owned the assets during the reported period. See Note 4 — Acquisitions.

Delaware Predecessor. Prior to the 2019 Delaware Acquisition, Oasis Petroleum's midstream services in the Delaware Basin were performed by OMS (the "Delaware Predecessor"). The consolidated financial statements include the results of the Delaware Predecessor for the year ended December 31, 2018 and prior to the effective date of the 2019 Delaware Acquisition for the year ended December 31, 2019.

The Delaware Predecessor financial statements have been prepared from the separate records maintained by Oasis Petroleum and may not necessarily be indicative of the actual results of operations that might have occurred if the Delaware Predecessor assets had been operated by the Partnership during the periods reported.

Predecessor. Prior to the initial public offering, Oasis Petroleum's midstream services were performed by Oasis Midstream Services LLC ("OMS"), a wholly-owned subsidiary of Oasis Petroleum, which constitutes the predecessor to the Partnership for accounting purposes (the "Predecessor"). The consolidated financial statements include the results of the Predecessor for the periods presented prior to the initial public offering on September 25, 2017. Certain midstream infrastructure assets, liabilities, revenues and expenses included in the Predecessor's historical financial statements have been excluded from the DevCos upon formation. These excluded assets are not included in the consolidated financial statements for the periods presented subsequent to the initial public offering on September 25, 2017. Substantially all of the services of the Predecessor were provided to Oasis Petroleum North America LLC ("OPNA"), a wholly-owned subsidiary of Oasis Petroleum that conducts Oasis Petroleum's crude oil and natural gas exploration and production activities. The Predecessor financial statements have been prepared from the separate records maintained by Oasis Petroleum and may not necessarily be indicative of the actual results of operations that might have occurred if the Predecessor had been operated separately during the periods reported.

Use of Estimates

Preparation of the Partnership's consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ significantly from those estimates. Management evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment.

Consolidation

The Partnership's consolidated financial statements include its accounts and the accounts of the DevCos, each of which is controlled by OMP GP LLC (the "General Partner"). All intercompany balances and transactions have been eliminated upon consolidation.

Variable interest entity. The Partnership determined that Bobcat DevCo is a variable interest entity ("VIE"), since OMS's equity at risk was established with non-substantive voting rights. As the Partnership has the authority to direct the activities that most significantly affect the economic performance of Bobcat DevCo, the Partnership is considered the primary beneficiary and consolidates Bobcat DevCo in its financial statements under the VIE consolidation model.

The Partnership determined that Bighorn DevCo, Beartooth DevCo and Panther DevCo are not VIEs and consolidates these entities in its financial statements under the voting interest consolidation model.

Non-controlling interests. The non-controlling interests represent Oasis Petroleum's retained ownership interests in Bobcat DevCo and Beartooth DevCo of 64.7% and 30%, respectively, as of December 31, 2019.

Significant Accounting Policies

Cash and cash equivalents. The Partnership classifies all unrestricted cash on hand and investments with original maturity dates less than 90 days as cash equivalents.

In the first quarter of 2019, the Partnership adopted Accounting Standards Update No. 2016-15, *Statement of Cash Flows* ("ASU 2016-15"), which is intended to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. ASU 2016-15 was applied on a retrospective basis. The adoption of ASU 2016-15 did not result in a material impact to the Partnership's financial position, cash flows, results of operations or financial statement disclosures.

Transactions with affiliates. Transactions between Oasis Petroleum, its affiliates and the Partnership have been identified in the consolidated financial statements as transactions with affiliates. See Note 5 — Transactions with Affiliates.

Property, plant and equipment. Property, plant and equipment consists primarily of pipelines, natural gas processing plants, produced and flowback water facilities and compressor stations. Property, plant and equipment is stated at the lower of historical cost less accumulated depreciation, or fair value, if impaired.

The Partnership capitalizes a portion of its interest expense incurred on its outstanding debt. The amount capitalized is determined by multiplying the capitalization rate by the average amount of eligible accumulated capital expenditures and is limited to actual interest costs incurred during the period. The accumulated capital expenditures included in the capitalized interest calculation begin when the first costs are incurred and end when the asset is either placed into service or written off. The Partnership capitalized $0.9 million, $4.9 million and $1.2 million of interest costs for the years ended December 31, 2019, 2018 and 2017, respectively. These amounts are amortized over the useful life of the related assets once the assets are placed in-service.

When assets are placed into service, management makes estimates with respect to useful lives and salvage values that management believes are reasonable. However, subsequent events could cause a change in estimates, thereby impacting future depreciation amounts. Uncertainties that may impact these estimates include, among others, changes in laws and regulations relating to environmental matters, including air and water quality, restoration and abandonment requirements, economic conditions and supply and demand in the area.

Depreciation is computed over the asset's estimated useful life using the straight line method based on estimated useful lives and asset salvage values. The weighted average life of each of the Partnership's pipelines, natural gas processing plants, produced and flowback water facilities, compressor stations, and other long-lived assets is 30 years. When properties are retired or otherwise disposed of, the related cost and accumulated depreciation are removed from the respective accounts and any profit or loss on disposition is recognized as gain or loss.

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

Fair value represents the estimated price between market participants to sell an asset in the principal or most advantageous market for the asset, based on assumptions a market participant would make. When warranted, management assesses the fair value of long-lived assets using commonly accepted techniques and may use more than one source in making such assessments. The factors used to determine fair value are subject to management's judgment and expertise and include, but are not limited to, recent third-party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors. Significant changes, such as changes in contract rates or terms, the condition of an asset or management's intent to utilize the asset, generally require management to reassess the cash flows related to long-lived assets. A reduction of the carrying value of fixed assets would represent a Level 3 fair value measurement.

If actual results are not consistent with assumptions and estimates, or assumptions and estimates change due to new information, the Partnership may be exposed to additional impairment charges. Ultimately, a prolonged period of lower commodity prices may adversely affect the estimate of future operating results through lower throughput volumes on the Partnership's assets, which could result in future impairment charges due to the potential impact on operations and cash flows.

Asset retirement obligations ("ARO"). The Partnership records the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred, with the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. For produced and flowback water disposal wells, this is the period in which the well is drilled or acquired. The ARO represents the estimated amount the Partnership will incur to plug, abandon and remediate the produced and flowback water properties at the end of their useful lives, in accordance with applicable state laws. The liability is accreted to its present value each period and the capitalized costs are depreciated using the straight-line method. The accretion expense is recorded as a component of depreciation and amortization in the Consolidated Statements of Operations.

Some assets, including certain pipelines and the Partnership's natural gas processing plants, have contractual or regulatory obligations to perform remediation and, in some instances, dismantlement and removal activities when the assets are abandoned. The Partnership is not able to reasonably estimate the fair value of the ARO for these assets because the settlement dates are indeterminable given the expected continued use of the assets with proper maintenance. The Partnership will record an ARO for these assets in the periods in which the settlement dates become reasonably determinable.

The Partnership determines the ARO, which represents a non-financial liability which is measured at fair value on a non-recurring basis, by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. These assumptions represent Level 3 inputs. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Deferred financing costs. The Partnership capitalizes directly attributable costs incurred in connection with obtaining debt financing. These costs are amortized over the term of the related financing using the straight-line method, which approximates the interest method. The amortization expense is recorded as a component of interest expense in the Partnership's Consolidated Statements of Operations. The deferred financing costs related to the Partnership's revolving credit facility are included in other assets on the Consolidated Balance Sheets.

Equity-based compensation. The Partnership has granted phantom unit awards and restricted unit awards under the Oasis Midstream Partners LP 2017 Long Term Incentive Plan ("LTIP"). The Partnership accounts for phantom unit awards as liability-classified awards in accordance with GAAP, since the Partnership intends to settle these awards in cash. The Partnership will be reimbursed by Oasis Petroleum for the cash settlement amount of these awards. The Partnership accounts for restricted units granted to certain independent directors of the General Partner as equity-classified awards in accordance with GAAP, as the Partnership intends to settle these awards in common units. Forfeitures associated with awards granted under the LTIP are accounted for when they occur.

In the first quarter of 2019, the Partnership adopted Accounting Standards Update No. 2017-09, *Scope of Modification Accounting* ("ASU 2017-09"), which provides guidance about which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting. ASU 2017-09 was adopted on a prospective basis. The adoption of ASU 2017-09 did not result in a material impact to the Partnership's financial position, cash flows, results of operations or financial statement disclosures.

Income taxes. The Partnership is not a taxable entity for United States federal income tax purposes or for the majority of states that impose an income tax. Generally, each partner is separately taxed on its share of taxable income. During the fourth quarter of 2019, the Partnership commenced operations in the Delaware Basin, and as a result, is subject to the Texas margin tax, which is considered an income tax under GAAP.

For periods prior to the initial public offering, the consolidated financial statements include a provision for income tax expense. Deferred federal and state income taxes were provided on temporary differences between the financial statement carrying amounts of recognized assets and liabilities and their respective tax bases as if the Partnership filed tax returns as a stand-alone entity.

Revenue recognition. In the first quarter of 2018, the Partnership adopted Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers* and a series of related accounting standards updates incorporated into GAAP as Accounting Standards Codification Topic 606 ("ASC 606") using the modified retrospective method. The adoption of ASC 606 did not result in a material impact to the Partnership's financial position, cash flows or results of operations. The Partnership has also modified current processes and controls to apply the requirements of the new standard and does not believe such modifications are material to its internal controls over financial reporting. Enhanced disclosures in accordance with the requirements of ASC 606 have been provided in Note 3 —Revenue Recognition.

The unit of account in ASC 606 is a performance obligation, which is a promise in a contract to transfer to a customer either a distinct good or service (or bundle of goods or services) or a series of distinct goods or services provided over a period of time. ASC 606 requires that a contract's transaction price, which is the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, is to be allocated to each performance obligation in the contract based on relative standalone selling prices and recognized as revenue when (point in time) or as (over time) the performance obligation is satisfied.

The Partnership generates revenues primarily by charging fees for (i) crude oil gathering, stabilization, blending, storage and transportation, (ii) natural gas gathering, gas lift, compression and processing, (iii) produced and flowback water gathering and disposal and (iv) freshwater supply and distribution.

The Partnership categorizes revenues as service revenues or product sales in its Consolidated Statements of Operations. For revenues generated under fee-based arrangements, the Partnership records the fees attributable to such arrangements as service revenues in its Consolidated Statements of Operations. Under fee-based arrangements, the Partnership does not take ownership of the volumes it handles for its customers and receives fees for midstream services it provides. Revenues are recognized based upon the transaction price at month-end under the right to invoice practical expedient. For revenues generated under purchase arrangements, the Partnership takes ownership of the product prior to sale and is the principal in the transaction. Revenues and expenses are recognized on a gross basis under Product sales and Costs of product sales, respectively, in the Consolidated Statements of Operations.

Common control transactions. The Partnership accounts for assets acquired from Oasis Petroleum and its subsidiaries as common control transactions whereby the net assets acquired are recorded at historical carrying value at the date of transfer. Consideration transferred in excess of the carrying value of the net assets acquired is recorded to equity as a deemed distribution. Common control transactions involving the transfer of a business or the transfer of net assets result in a change in reporting entity and require prior periods to be retrospectively adjusted. To the extent such transactions require prior periods to be retrospectively adjusted, historical net equity amounts prior to the transaction date are reflected in predecessor equity.

Business combinations (excluding common control transactions). The Partnership accounts for business combinations under the acquisition method of accounting. An income, market or cost valuation method may be utilized to estimate the fair value of the assets acquired, liabilities assumed, and non-controlling interest, if any, in a business combination. Fair value is determined on the acquisition date. Acquisition-related costs are expensed as incurred in connection with each business combination. If the initial accounting for the business combination is incomplete by the end of the reporting period in which the acquisition occurs, an estimate will be recorded. Subsequent to the acquisition, and not later than one year from the acquisition date, the Partnership will record any material adjustments to the initial estimate based on new information obtained about facts and circumstances that existed as of the acquisition date.

The Partnership makes various assumptions in estimating the fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. The income valuation method represents the present value of future cash flows over the life of the asset using discrete financial forecasts. Such discrete financial forecasts rely on estimates and assumptions made by management. The most significant assumptions relate to management's estimates of throughput volumes, future operating and development costs, long-term growth rates and a market-based weighted average cost of capital. The market valuation method uses prices paid for a reasonably similar asset by other purchasers in the market, with adjustments relating to any differences between the assets. The cost valuation method is based on the replacement cost of a comparable asset at prices at the time of the acquisition reduced for depreciation of the asset. Any excess of the acquisition price over the estimated fair value of net assets acquired is recorded as goodwill. Any excess of the estimated fair value of net assets acquired over the acquisition price is recorded in current earnings as a gain on bargain purchase.

In the first quarter of 2019, the Partnership adopted Accounting Standards Update No. 2017-01, *Clarifying the Definition of a Business* ("ASU 2017-01"), which provides guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. ASU 2017-01 was adopted on a prospective basis. The adoption of ASU 2017-01 did not result in a material impact to the Partnership's financial position, cash flows, results of operations or financial statement disclosures.

Leases. In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2016-02, *Leases* ("ASU 2016-02"), which established a right-of-use ("ROU") model that requires a lessee to recognize an operating lease asset and lease liability on the balance sheet, with the exception of short-term leases. Accounting Standards Codification 842, Leases ("ASC 842"), was subsequently amended by ASU No. 2018-01, *Land easement practical expedient for transition to Topic 842* ("ASU 2018-01"); ASU No. 2018-10, *Codification Improvements to Topic 842;* and ASU No. 2018-11, *Targeted Improvements*.

The new standard is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The effective date and transition requirements for the amendments are the same as the effective date for ASU 2016-02. A modified retrospective transition approach is required, applying the new standard to all leases existing at the date of initial application. An entity may choose to use either (i) its effective date or (ii) the beginning of the earliest comparative period presented in the financial statements as its date of initial application.

The Partnership adopted the new standard as of January 1, 2019, using the required modified retrospective approach and elected the option to recognize a cumulative effect adjustment of initially applying the guidance to the opening balance of retained earnings in the period of adoption. Prior period amounts were not adjusted.

The Partnership elected the package of practical expedients under the transition guidance within the new standard, including the practical expedient to not reassess under the new standard any prior conclusions about lease identification, lease classification and initial direct costs; the use-of hindsight practical expedient; the practical expedient to not reassess the prior accounting treatment for existing or expired land easements; and the practical expedient pertaining to combining lease and non-lease components for all asset classes. In addition, the Partnership elected not to apply the recognition requirements of ASC 842 to short-term leases, and as such, recognition of lease payments for short-term leases are recognized in net income on a straight line basis. See Note 9 — Leases for the adoption impact and disclosures required by ASC 842.

Concentrations of Market and Credit Risk

The Partnership has limited direct exposure to risks associated with fluctuating commodity prices due to the nature of its business and its long-term, fixed-fee contractual arrangements with customers. However, to the extent that the future contractual arrangements with customers, including Oasis Petroleum or third parties, do not provide for fixed-fee structures, the Partnership may become subject to commodity price risk. Additionally, as substantially all of the Partnership's revenues are derived from Oasis Petroleum, the Partnership is indirectly subject to risks associated with fluctuating commodity prices to the extent that lower commodity prices adversely affect Oasis Petroleum's production, drilling schedule, financial condition, leverage, market reputation, liquidity, results of operations or cash flows.

Recent Accounting Pronouncements

Fair Value Measurement. In August 2018, the FASB issued Accounting Standards Update No. 2018-13, *Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement* ("ASU 2018-13"), which improves the effectiveness of the disclosure requirements for fair value measurements. The changes affect all companies that are required to include fair value measurement disclosures. ASU 2018-13 is effective for fiscal years beginning after December 15, 2019, including interim periods within those years. An entity is permitted to early adopt the removed or modified disclosures upon the issuance of ASU 2018-13 and may delay adoption of the additional disclosures until their effective date. The Partnership does not expect the adoption of this guidance to have an impact on its financial position, cash flows or results of operations, but it may result in changes to disclosures.

Financial Instruments - Credit Losses. In June 2016, the FASB issued Accounting Standards Update No. 2016-13, *Financial Instruments — Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments* ("ASU 2016-13"), which replaces the incurred loss impairment methodology in current GAAP with a methodology that reflects expected credit losses and requires consideration of a broader range of reasonable and supportable information, including forecasts, to develop credit loss estimates. ASU 2016-13 requires entities to use the new methodology to measure impairment of financial instruments, including accounts receivable, and may result in earlier recognition of credit losses than under current GAAP. ASU 2016-13 is effective for fiscal years beginning after December 15, 2019. Although the Partnership continues to evaluate ASU 2016-13, based on our current credit portfolio the Partnership does not expect the adoption of this standard to have a material impact on its financial position, cash flows or results of operations, but it may result in changes to disclosures.

3. Revenue Recognition

The Partnership categorizes revenues as service revenues or product sales under the following types of arrangements:

Fee-based arrangements. Revenues generated under fee-based arrangements are reported as service revenues on the Consolidated Statements of Operations. Under fee-based arrangements, the Partnership receives a fee for midstream services provided to its customers, and revenues are recognized using the output method for measuring the satisfaction of performance obligations. Revenues earned under fee-based arrangements are generally directly related to the volume of crude oil, natural gas and produced and flowback water that flows through the Partnership's systems, and the Partnership does not take ownership to the volumes it handles for its customers. Payments under fee-based arrangements are generally due 30 days after receipt of invoice. The Partnership generates revenues under fee-based arrangements as follows:

- *Crude oil and natural gas.* The Partnership is party to certain contracts with customers for crude oil gathering, stabilization, blending, storage and transportation, as well as natural gas gathering, compression, processing and gas lift services. Under these customer contracts, the Partnership provides daily integrated midstream services on a stand ready basis over a period of time, which represents a single performance obligation since the customer simultaneously receives and consumes the benefits of these services on a daily basis. Satisfaction of the performance obligation is measured as each day of service is completed, which directly corresponds with its right to consideration from the customer. Revenues associated with these contracts are recognized based upon the transaction price at month-end under the right to invoice practical expedient.

- *Produced and flowback water.* The Partnership is party to certain contracts with customers for produced and flowback water gathering and disposal services. Under these customer contracts, the Partnership provides daily integrated midstream services on a stand ready basis over a period of time, which represents a single performance obligation since the customer simultaneously receives and consumes the benefits of these services on a daily basis. Satisfaction of the performance obligation is measured as each day of service is completed, which directly corresponds with its right to consideration from the customer. Revenues associated with these contracts are recognized based upon the transaction price at month-end under the right to invoice practical expedient.

Purchase arrangements. Revenues generated under purchase arrangements are reported as product sales on the Consolidated Statements of Operations. Under purchase arrangements, revenues and expenses are recognized on a gross basis since the Partnership takes control of the product prior to sale and is the principal in the transaction. The Partnership recognizes revenues using the output method for measuring the satisfaction of performance obligations based upon the volume of natural gas, natural gas liquids ("NGLs") or freshwater delivered to its customers. Revenues associated with purchase arrangements are recognized at a point in time based upon the transaction price when title, control and risk of loss transfers to the customer, which occurs at the delivery point. Payments under purchase arrangements are generally due 30 days after receipt of invoice. The Partnership generates revenues under purchase arrangements as follows:

- *Natural gas and NGL.* The Partnership is party to certain purchase arrangements pursuant to which the Partnership purchases natural gas from a third party at a connection point and obtains control prior to performing services. The Partnership gathers, compresses and/or processes the gas and then redelivers the residue gas and NGLs to a different counterparty at market-based prices.
- *Freshwater.* The Partnership is party to certain contracts with customers for freshwater supply and distribution. Under these customer contracts, the Partnership supplies and distributes freshwater to its customers for hydraulic fracturing and production optimization. These contracts contain multiple distinct performance obligations since each freshwater barrel can be sold separately and is not dependent or highly interrelated with other barrels.

Disaggregation of revenues

The following table summarizes revenues associated with contracts with customers for crude oil, natural gas and water services for the periods presented:

	Year Ended December 31,		
	2019(1)	2018(1)	2017
	(In thousands)		
Service revenues			
Crude oil and natural gas revenues	$ 197,015	$ 134,562	$ 85,828
Produced and flowback water revenues	126,588	118,405	84,350
Total service revenues	323,603	252,967	170,178
Product revenues			
Natural gas and NGL revenues	65,154	1,445	—
Freshwater revenues	21,434	19,358	12,038
Total product revenues	86,588	20,803	12,038
Total revenues	$ 410,191	$ 273,770	$ 182,216

(1) Retrospectively adjusted for the transfer of net assets between entities under common control. See Note 4 — Acquisitions.

Prior period performance obligations

The Partnership records revenue when the performance obligations under the terms of its customer contracts are satisfied. The Partnership measures the satisfaction of its performance obligations using the output method based upon the volume of crude oil, natural gas or water that flows through its systems. In certain cases, the Partnership is required to estimate these volumes during a reporting period and record any differences between the estimated volumes and actual volumes in the following reporting period. Such differences have historically not been significant. For the years ended December 31, 2019, 2018 and 2017, revenue recognized related to performance obligations satisfied in prior reporting periods was not material.

Contract balances

Contract balances are the result of timing differences between revenue recognition, billings and cash collections. Contract liabilities are recorded for consideration received from customers primarily related to (i) temporary deficiency quantities under minimum volume commitments which are recognized as revenue when the customer makes up the volumes or the deficiency makeup period expires and (ii) aid in construction payments received from customers which are recognized as revenue over the expected period of future benefit. The Partnership does not recognize contract assets or contract liabilities under its customer contracts for which invoicing occurs once the Partnership's performance obligations have been satisfied and payment is unconditional. Contract liabilities are classified as current or long-term based on the timing of when the Partnership expects to recognize revenue. As of December 31, 2018, there were no contract balances recorded.

The following table summarizes the changes in contract liabilities for the year ended December 31, 2019:

	(In thousands)
Beginning of period	$ —
Cash received	3,750
Revenue recognized	(69)
End of period	$ 3,681

Remaining performance obligations

ASC 606 requires presentation of information about partially and wholly unsatisfied performance obligations under contracts that exist as of the end of the period. The following table presents estimated revenue allocated to remaining performance obligations for contracted revenues that are unsatisfied (or partially satisfied) as of December 31, 2019:

	(In thousands)
2020	$ 20,648
2021	22,393
2022	19,244
2023	12,624
2024	11,870
Thereafter	2,768
Total	$ 89,547

The partially and wholly unsatisfied performance obligations presented in the table above are generally limited to customer contracts which have fixed pricing and fixed volume terms and conditions, which generally include customer contracts with minimum volume commitment payment obligations.

The Partnership has elected practical expedients, pursuant to ASC 606, to exclude from the presentation of remaining performance obligations: (i) contracts with index-based pricing or variable volume attributes in which such variable consideration is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct service that forms part of a series of distinct services and (ii) contracts with an original expected duration of one year or less.

4. Acquisitions

2019 Delaware Acquisition. On November 1, 2019, the Partnership entered into an agreement with Oasis Petroleum, pursuant to which Oasis Petroleum agreed to assign to Panther DevCo certain crude oil gathering and produced and flowback water gathering and disposal assets in the Delaware Basin in exchange for cash consideration of approximately $24.9 million. The Partnership funded the cash consideration with borrowings under the Revolving Credit Facility. For the period from November 1, 2019 through December 31, 2019, the Partnership recognized $1.4 million in revenues and $0.7 million in net income related to the 2019 Delaware Acquisition.

The 2019 Delaware Acquisition was accounted for as a transfer of net assets between entities under common control. Prior to the 2019 Delaware Acquisition, Oasis Petroleum's midstream services in the Delaware Basin were performed by OMS and were not included in the consolidated financial statements of the Partnership. In accordance with FASB authoritative guidance under Accounting Standards Codification Topic 805-50 ("ASC 805-50"), the Partnership recorded the net assets acquired at historical carrying value and recast its financial statements to include such net assets from the date of common control.

The Partnership recast its consolidated financial statements as of and for the year ended December 31, 2018, and prior to the effective date of November 1, 2019 for the year ended December 31, 2019. For those periods requiring recast, the consolidated financial statements for periods prior to the effective date were prepared from Oasis Petroleum's historical cost-basis accounts.

The following table summarizes the assets acquired, liabilities assumed and consideration paid:

	Effective November 1, 2019
	(In thousands)
Cash consideration paid to Oasis Petroleum	$ 24,939
Property, plant and equipment	$ 35,272
Accumulated depreciation and amortization	(439)
Accrued capital costs	(9,256)
Accrued operating expenses	(746)
Asset retirement obligations	(132)
Total net assets acquired	$ 24,699
Consideration paid in excess of book value of net assets[1]	$ 240

(1) Consideration paid in excess of book value was recorded to Partnership equity as a deemed distribution in accordance with FASB authoritative guidance for common control transactions.

The following tables present the Partnership's financial position, results of operations and cash flows giving effect to the 2019 Delaware Acquisition as of and for the year ended December 31, 2018:

	December 31, 2018		
	As Previously Reported	2019 Delaware Acquisition	As Recasted
		(In thousands)	
ASSETS			
Current assets			
Cash and cash equivalents	$ 6,649	$ —	$ 6,649
Accounts receivable	2,481	—	2,481
Accounts receivable – Oasis Petroleum	80,805	217	81,022
Prepaid expenses	1,418	—	1,418
Other current assets	22	—	22
Total current assets	91,375	217	91,592
Property, plant and equipment	933,155	9,423	942,578
Less: accumulated depreciation and amortization	(62,730)	—	(62,730)
Total property, plant and equipment, net	870,425	9,423	879,848
Other assets	2,452	—	2,452
Total assets	$ 964,252	$ 9,640	$ 973,892
LIABILITIES AND EQUITY			
Current liabilities			
Accounts payable	$ 2,180	$ —	$ 2,180
Accounts payable – Oasis Petroleum	33,014	—	33,014
Accrued liabilities	57,657	3,297	60,954
Accrued interest payable	442	—	442
Total current liabilities	93,293	3,297	96,590
Long-term debt	318,000	—	318,000
Asset retirement obligations	1,514	116	1,630
Total liabilities	412,807	3,413	416,220
Equity			
Limited partners			
Common units	192,581	—	192,581
Subordinated units	45,937	—	45,937
General Partner	112	—	112
Total partners' equity	238,630	—	238,630
Non-controlling interests	312,815	—	312,815
Delaware Predecessor	—	6,227	6,227
Total equity	551,445	6,227	557,672
Total liabilities and equity	$ 964,252	$ 9,640	$ 973,892

	Year Ended December 31, 2018		
	As Previously Reported	2019 Delaware Acquisition	As Recasted
	(In thousands, except per unit data)		
Revenues			
Midstream services – Oasis Petroleum	$ 248,216	$ 2,147	$ 250,363
Midstream services – third parties	2,604	—	2,604
Product sales – Oasis Petroleum	17,476	—	17,476
Product sales – third parties	3,327	—	3,327
Total revenues	271,623	2,147	273,770
Operating expenses			
Costs of product sales	7,433	—	7,433
Operating and maintenance	63,123	562	63,685
Depreciation and amortization	28,404	5	28,409
General and administrative	23,897	—	23,897
Total operating expenses	122,857	567	123,424
Operating income	148,766	1,580	150,346
Other income (expense)			
Interest expense, net of capitalized interest	(2,343)	(237)	(2,580)
Other income (expense)	(14)	—	(14)
Total other expense, net	(2,357)	(237)	(2,594)
Income before income taxes	146,409	1,343	147,752
Income tax expense	—	—	—
Net income	146,409	1,343	147,752
Less: Net income attributable to Delaware Predecessor	—	1,343	1,343
Less: Net income attributable to non-controlling interests	96,354	—	96,354
Net income attributable to OMP LP	50,055	—	50,055
Less: Net income attributable to General Partner	112	—	112
Net income attributable to limited partners	$ 49,943	$ —	$ 49,943
Earnings per limited partner unit (Note 14)			
Common units – basic and diluted	$ 1.82	$ —	$ 1.82
Weighted average number of limited partners units outstanding (Note 14)			
Common units – basic	14,504	—	14,504
Common units – diluted	14,519	—	14,519

	Year Ended December 31, 2018		
	As Previously Reported	2019 Delaware Acquisition	As Recasted
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 146,409	$ 1,343	$ 147,752
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	28,404	5	28,409
Equity-based compensation expenses	356	—	356
Deferred financing costs amortization and other	(519)	—	(519)
Working capital and other changes:			
Change in accounts receivable	3,411	(217)	3,194
Change in prepaid expenses	(640)	—	(640)
Change in accounts payable and accrued liabilities	27,613	201	27,814
Change in other assets and liabilities, net	(22)	—	(22)
Net cash provided by operating activities	205,012	1,332	206,344
Cash flows from investing activities:			
Capital expenditures	(276,810)	(6,216)	(283,026)
Net cash used in investing activities	(276,810)	(6,216)	(283,026)
Cash flows from financing activities:			
Capital contributions from non-controlling interests	140,277	—	140,277
Capital contributions from Delaware Predecessor, net	—	4,884	4,884
Proceeds from sale of common units, net of offering costs	44,503	—	44,503
Distributions to non-controlling interests	(128,903)	—	(128,903)
Distribution to Oasis Petroleum for contributed assets	(172,429)	—	(172,429)
Distributions to unitholders	(44,918)	—	(44,918)
Deferred financing costs	(966)	—	(966)
Proceeds from revolving credit facility	275,000	—	275,000
Principal payments on revolving credit facility	(35,000)	—	(35,000)
Net cash provided by financing activities	77,564	4,884	82,448
Increase in cash and cash equivalents	5,766	—	5,766
Cash:			
Beginning of period	883	—	883
End of period	$ 6,649	$ —	$ 6,649
Supplemental cash flow information:			
Cash paid for interest, net of capitalized interest	$ 1,817	$ 237	$ 2,054
Supplemental non-cash transactions:			
Change in accrued capital expenditures	$ (4,890)	$ 3,096	$ (1,794)
Change in asset retirement obligations	198	116	314
Reimbursement of capital expenditures from Oasis Petroleum	7,176	—	7,176

2018 Dropdown Acquisition. On November 19, 2018, the Partnership completed transactions contemplated by a contribution agreement (the “Contribution Agreement”) dated as of November 7, 2018, with OMS Holdings LLC (“OMS Holdings”), OMS, OMP GP LLC, OMP Operating, and for certain limited purposes set forth therein, Oasis Petroleum. Pursuant to the Contribution Agreement, Oasis Petroleum caused OMS to contribute to OMP Operating, as the Partnership’s designee, (a) an additional 15% limited liability company interest in Bobcat DevCo, and (b) an additional 30% limited liability company interest in Beartooth DevCo (collectively, the “Contributed Assets”) for consideration of approximately $251.4 million (the “Purchase Price”), consisting of approximately $172.4 million in cash and 3,950,000 common units, representing limited partner interests in the Partnership (the “2018 Dropdown Acquisition”). The Purchase Price includes post-effective date adjustments of approximately $1.4 million. The Partnership funded the cash portion of the Purchase Price with a combination of borrowings under the Revolving Credit Facility and proceeds from a public offering of common units. The effective date of the 2018 Dropdown Acquisition was July 1, 2018, and the 2018 Dropdown Acquisition closed on November 19, 2018.

Prior to the 2018 Dropdown Acquisition, the Contributed Assets were reflected as non-controlling interests in the consolidated financial statements. In accordance with FASB authoritative guidance under ASC 810-10 for non-controlling interests in a common control transaction, the Partnership accounted for the 2018 Dropdown Acquisition as an equity transaction and adjusted the carrying amount of non-controlling interests in the consolidated financial statements to reflect the change in ownership interests. Furthermore, as the Partnership acquired additional interests in previously consolidated subsidiaries, the 2018 Dropdown Acquisition did not result in a change in reporting entity, as defined under ASC 805-50, and was accounted for on a prospective basis.

5. Transactions with Affiliates

Revenues. The Partnership generates substantially all of its revenues through 15-year, fee-based contractual arrangements with wholly-owned subsidiaries of Oasis Petroleum for midstream services. These services include (i) gas gathering, compression, processing and gas lift services; (ii) crude gathering, stabilization, blending, storage and transportation services; (iii) produced and flowback water gathering and disposal services; and (iv) freshwater supply and distribution services. The revenue earned from these services is generally directly related to the volume of crude oil, natural gas, and produced and flowback water and freshwater that flows through the Partnership’s systems, and the Partnership does not take ownership of the crude oil or natural gas that it handles for Oasis Petroleum.

Expenses. Oasis Petroleum provides substantial labor and overhead support for the Partnership pursuant to a 15-year services and secondment agreement (the “Services and Secondment Agreement”). Oasis Petroleum performs centralized corporate, general and administrative services for the Partnership, such as legal, corporate recordkeeping, planning, budgeting, regulatory, accounting, billing, business development, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, investor relations, cash management and banking, payroll, internal audit, tax and engineering. Oasis Petroleum has also seconded to the Partnership certain of its employees to operate, construct, manage and maintain its assets. The Partnership reimburses Oasis Petroleum for direct and allocated general and administrative expenses incurred by Oasis Petroleum for the provision of these services. The expenses of executive officers and non-executive employees of Oasis Petroleum are allocated to the Partnership based on the amount of time spent managing its business and operations.

For the periods prior to the initial public offering, shared services and direct labor were allocated to the Predecessor primarily based on headcount and direct usage during the respective years. Management believes that these allocations are reasonable and reflect the utilization of services provided and benefits received, but may differ from the cost that would have been incurred had the Predecessor operated as a stand-alone company for the periods presented prior to the initial public offering.

Additionally, for the periods prior to the initial public offering and the 2019 Delaware Acquisition, interest expense was recognized by the Predecessor and Delaware Predecessor related to its funding activity with Oasis Petroleum based on capital expenditures for the period using the weighted average effective interest rate for Oasis Petroleum’s long-term indebtedness.

The Partnership’s general and administrative expenses include $28.0 million, $21.1 million and $12.8 million from affiliate transactions with Oasis Petroleum for the years ended December 31, 2019, 2018 and 2017, respectively. Interest expense, net of capitalized interest, includes $0.6 million and $0.2 million related to the funding activity of the Delaware Predecessor with Oasis Petroleum for the years ended December 31, 2019 and 2018, respectively. In addition, interest expense, net of capitalized interest, includes $6.9 million related to funding activity of the Predecessor prior to the initial public offering for the year ended December 31, 2017.

2019 Capital Expenditures Arrangement. On February 22, 2019, the Partnership entered into a memorandum of understanding (the “MOU”) with Oasis Petroleum regarding the funding of Bobcat DevCo’s capital expenditures for the 2019 calendar year (the “2019 Capital Expenditures Arrangement”). Pursuant to the Amended and Restated Limited Liability Company Agreement of Bobcat DevCo LLC, as amended (the “First A&R Bobcat LLCA”), the Partnership and Oasis Petroleum are each required to make pro-rata capital contributions to Bobcat DevCo in accordance with their respective percentage ownership interests in Bobcat DevCo.

Pursuant to the MOU, the Partnership agreed to make up to $80.0 million of capital expenditures to Bobcat DevCo that Oasis Petroleum would otherwise be required to contribute under the First A&R Bobcat LLCA. In connection with execution of the MOU, the Partnership and Oasis Petroleum amended the First A&R Bobcat LLCA and entered into the Second Amended and Restated Limited Liability Company Agreement of Bobcat DevCo LLC (the “Second A&R Bobcat LLCA”). The Second A&R Bobcat LLCA includes provisions applicable to the disproportionate capital contributions that the Partnership made to Bobcat

DevCo in connection with the 2019 Capital Expenditures Arrangement. Pursuant to the Second A&R Bobcat LLCA, upon the occurrence of a disproportionate capital contribution, the percentage interests of the Partnership and Oasis Petroleum in Bobcat DevCo were adjusted to take into account the amount of the disproportionate capital contribution.

During the year ended December 31, 2019, the Partnership made capital contributions to Bobcat DevCo pursuant to the 2019 Capital Expenditures Arrangement of $73.0 million. As a result, the Partnership's ownership interest in Bobcat DevCo increased from 25% as of December 31, 2018 to 35.3% as of December 31, 2019. The 2019 Capital Expenditures Arrangement ended on December 31, 2019.

6. Accrued Liabilities

Accrued liabilities consist of the following:

	December 31,	
	2019	2018[1]
	(In thousands)	
Accrued capital costs	$ 33,105	$ 46,049
Accrued operating expenses	12,149	13,740
Other accrued liabilities	4,956	1,165
Total accrued liabilities	$ 50,210	$ 60,954

(1) Retrospectively adjusted for the transfer of net assets between entities under common control. See Note 4 — Acquisitions.

7. Property, Plant and Equipment

Property, plant and equipment consists of the following:

	December 31,	
	2019	2018[1]
	(In thousands)	
Pipelines	$ 523,576	$ 395,087
Natural gas processing plants	296,609	278,680
Produced and flowback water facilities	121,797	103,572
Compressor stations	143,276	126,019
Other property and equipment	34,231	33,829
Construction in progress	36,014	5,391
Total property, plant and equipment	1,155,503	942,578
Less: accumulated depreciation and amortization	(98,982)	(62,730)
Total property, plant and equipment, net	$ 1,056,521	$ 879,848

(1) Retrospectively adjusted for the transfer of net assets between entities under common control. See Note 4 — Acquisitions.

8. Long-Term Debt

On September 25, 2017, the Partnership entered into a credit agreement (the "Credit Agreement") for a revolving credit facility with OMP Operating as borrower (the "Revolving Credit Facility"), which has a maturity date of September 25, 2022. The Revolving Credit Facility is available to fund working capital and to finance acquisitions and other capital expenditures of the Partnership. On May 6, 2019, the Partnership entered into the Second Amendment to the Credit Agreement to (i) increase the aggregate amount of commitments from $400.0 million to $475.0 million; (ii) provide for the ability to further increase commitments to $675.0 million; and (iii) add a new lender to the bank group. On August 16, 2019, the Partnership entered into the Third Amendment to the Credit Agreement to (i) increase the aggregate amount of commitments from $475.0 million to $575.0 million and (ii) provide for the ability to further increase commitments to $775.0 million. As of December 31, 2019, the aggregate amount of commitments under the Revolving Credit Facility were $575.0 million.

The Revolving Credit Facility includes a letter of credit sublimit of $10.0 million and a swingline loans sublimit of $10.0 million. All obligations of OMP Operating, as the borrower under the Revolving Credit Facility, are unconditionally guaranteed on a joint and several basis by the Partnership, Bighorn DevCo and Panther DevCo.

The Revolving Credit Facility is collateralized by mortgages and other interests on substantially all of the Partnership's and its subsidiaries' properties and assets, including the equity interests in all present and future subsidiaries (subject to certain exceptions). Some or all of the collateral owned by Bobcat DevCo and Beartooth DevCo is subject to an intercreditor agreement between Wells Fargo, National Association ("Wells Fargo"), as administrative agent for the Revolving Credit Facility, and Wells Fargo as the administrative agent for the revolving credit facility of Oasis Petroleum, and acknowledged by OMS, Bobcat DevCo and Beartooth DevCo. The Revolving Credit Facility provides for customary representations, warranties and covenants, including, among other things, covenants relating to financial and collateral reporting, notices of material events, maintenance of the existence of the business and its properties, payment of obligations, the Partnership's ability to enter into certain hedging agreements, limitations on the Partnership's ability to sell or acquire properties and limitations on indebtedness and liens, dividends and distributions, transactions with affiliates and certain fundamental transactions.

Borrowings under the Revolving Credit Facility bear interest at a rate per annum equal to the applicable margin (as described below) plus (i) with respect to Eurodollar Loans, the Adjusted LIBO Rate (as defined in the Credit Agreement) or (ii) with respect to ABR Loans, the greatest of (A) the Prime Rate in effect on such day, (B) the Federal Funds Effective Rate in effect on such day plus 1/2 of 1.00% or (C) the Adjusted LIBO Rate for a one-month interest period on such day plus 1.00% (each as defined in the Credit Agreement). The unused portion of the Revolving Credit Facility is subject to a commitment fee ranging from 0.375% to 0.500%. As of December 31, 2019 and 2018, the weighted average interest rate on the Revolving Credit Facility was 3.8% and 4.2%, respectively.

The applicable margin for borrowings under the Revolving Credit Facility is determined in accordance with the Credit Agreement as follows:

Consolidated Total Leverage Ratio	Applicable Margin for Eurodollar Loans	Applicable Margin for ABR Loans	Commitment Fee Rate
Less than or equal to 3.00 to 1.00	1.75 %	0.75 %	0.375 %
Greater than 3.00 to 1.00 but less than or equal to 3.50 to 1.00	2.00 %	1.00 %	0.375 %
Greater than 3.50 to 1.00 but less than or equal to 4.00 to 1.00	2.25 %	1.25 %	0.500 %
Greater than 4.00 to 1.00 but less than or equal to 4.50 to 1.00	2.50 %	1.50 %	0.500 %
Greater than 4.50 to 1.00	2.75 %	1.75 %	0.500 %

The Revolving Credit Facility also requires the Partnership to maintain the following financial covenants as of the end of each fiscal quarter:

- Consolidated Total Leverage Ratio: Prior to the date on which one or more of the credit parties have issued an aggregate principal amount of at least $150.0 million of senior notes (as permitted under the Revolving Credit Facility) (such date the "Covenant Changeover Date") and commencing with the fiscal quarter ended December 31, 2018, the Partnership and OMP Operating's ratio of Total Debt to EBITDA (each as defined in the Credit Agreement) on a quarterly basis may not exceed 4.50 to 1.00 (or during an Acquisition Period (as defined in the Credit Agreement), 5.00 to 1.00). On a quarterly basis following the Covenant Changeover Date, the Partnership and OMP Operating's ratio of Total Debt to EBITDA may not exceed 5.25 to 1.00.
- Consolidated Senior Secured Leverage Ratio: On a quarterly basis, commencing with the date the Covenant Changeover Date occurs, the Partnership and OMP Operating's ratio of Consolidated Senior Secured Funded Debt to EBITDA (each as defined in the Credit Agreement) may not exceed 3.75 to 1.00.
- Consolidated Interest Coverage Ratio: On a quarterly basis prior to the Covenant Changeover Date and commencing with the fiscal quarter ended December 31, 2018, the Partnership and OMP Operating's ratio of EBITDA to Consolidated Interest Expense (each as defined in the Credit Agreement) may not be less than 3.00 to 1.00 and on a quarterly basis following the Covenant Changeover Date, the Partnership and OMP Operating's ratio of EBITDA to Consolidated Interest Expense may not be less than 2.50 to 1.00.

The Partnership was in compliance with the financial covenants under the Revolving Credit Facility as of December 31, 2019.

As of December 31, 2019, the Partnership had $458.5 million of borrowings and a $1.7 million letter of credit outstanding under the Revolving Credit Facility, resulting in an unused borrowing capacity of $114.8 million. As of December 31, 2018, the Partnership had $318.0 million of borrowings outstanding and an unused borrowing capacity of $82.0 million. The fair value of the Revolving Credit Facility approximates book value since borrowings under the Revolving Credit Facility bear interest at rates which are tied to current market rates.

9. Leases

As discussed in Note 2 — Summary of Significant Accounting Policies and Basis of Presentation, the Partnership adopted ASC 842 as of January 1, 2019 using the modified retrospective method, which resulted in the Partnership recognizing offsetting operating lease ROU assets and lease liabilities of $4.1 million. The Partnership did not have any finance leases as of the date of adoption. There was no impact to the opening equity balance as a result of the adoption of ASC 842. Prior period amounts were not adjusted and continue to be reported in accordance with previous guidance, Accounting Standards Codification 840 (“ASC 840”).

In accordance with the adoption of ASC 842, management determines whether an arrangement is a lease at its inception. The Partnership’s operating and finance leases consist primarily of equipment and land easements. The operating lease ROU asset also includes any lease incentives in the recognition of the present value of future lease payments. The Partnership considers renewal and termination options in determining the lease term used to establish its ROU assets and lease liabilities to the extent the Partnership is reasonably certain to exercise the renewal or termination. The Partnership’s lease agreements do not contain any material residual value guarantees or material restrictive covenants.

As most of the Partnership’s leases do not provide an implicit rate, the Partnership uses its incremental borrowing rate based on the information available at commencement date in determining the present value of future lease payments. The Partnership has determined the respective incremental borrowing rates based upon the rate of interest that would have been paid on a collateralized basis over similar tenors to that of the leases.

The Partnership’s components of lease costs were as follows for the year ended December 31, 2019:

	(In thousands)
Operating lease costs	$ 3,204
Variable lease costs (1)	414
Short-term lease costs	144
Finance lease costs:	
Amortization of ROU assets	26
Interest on lease liabilities	20
Total lease costs	$ 3,808

(1) Based on payments made by the Partnership to lessors for the right to use an underlying asset that vary because of changes in circumstances occurring after the commencement date, other than the passage of time, such as property taxes, operating and maintenance costs, which do not depend on an index or rate.

The operating lease costs disclosed above are included in operating and maintenance expenses on the Partnership’s Consolidated Statements of Operations. The finance lease costs for the amortization of ROU assets and the interest on lease liabilities disclosed above are included in depreciation and amortization and interest expense, net of capitalized interest, respectively, on the Partnership’s Consolidated Statements of Operations.

As of December 31, 2019, maturities of the Partnership’s lease liabilities were as follows:

	Operating Leases	Finance Leases
	(In thousands)	
2020	$ 3,150	$ 11
2021	1,530	45
2022	743	45
2023	—	45
2024	—	45
Thereafter	—	639
Total future lease payments	5,423	830
Less: Imputed interest	202	273
Present value of future lease payments	$ 5,221	$ 557

As of December 31, 2018, future minimum annual rental commitments under non-cancelable leases under ASC 840 were as follows:

	(In thousands)
2019	$ 736
2020	—
2021	—
2022	—
2023	—
Thereafter	—
Total future minimum lease payments	$ 736

Supplemental balance sheet information related to the Partnership's leases are as follows:

	Balance Sheet Location	As of December 31, 2019 (In thousands)
Assets		
Operating lease assets	Operating lease right-of-use assets	$ 5,207
Finance lease assets(1)	Other assets	602
Total lease assets		$ 5,809
Liabilities		
Current		
Operating lease liabilities	Current operating lease liabilities	$ 3,005
Finance lease liabilities	Other current liabilities	5
Long-term		
Operating lease liabilities	Operating lease liabilities	2,216
Finance lease liabilities	Other liabilities	552
Total lease liabilities		$ 5,778

(1) Finance lease ROU assets recorded net of accumulated amortization of $0.03 million as of December 31, 2019.

Supplemental cash flow information and non-cash transactions related to the Partnership's leases are as follows:

	December 31, 2019 (In thousands)
Cash paid for amounts included in the measurement of lease liabilities	
Operating cash flows from operating leases	$ 3,107
Operating cash flows from finance leases	20
Financing cash flows from finance leases	59
ROU assets obtained in exchange for lease obligations	
Operating leases	$ 4,109
Finance leases	660

Weighted-average remaining lease terms and discount rates for the Partnership's leases are as follows:

	As of December 31, 2019
Operating Leases	
Weighted average remaining lease term	2.0 years
Weighted average discount rate	4.1 %
Finance Leases	
Weighted average remaining lease term	19.2 years
Weighted average discount rate	4.3 %

10. Income Taxes

The Partnership is not a taxable entity for U.S. federal income tax purposes, and taxes are generally borne by unitholders through the allocation of taxable income. In connection with the initial public offering, Predecessor current and deferred tax liabilities of $104.0 million were eliminated upon consummation of the Partnership. The Partnership recorded a de minimis state income tax provision for the year ended December 31, 2019 associated with the Texas margin tax. As of December 31, 2019, the reported amounts of the Partnership's assets and liabilities exceeded the tax basis by $122.7 million.

The provision for income taxes included in the Consolidated Statements of Operations for the periods presented relates to the Predecessor. The Predecessor is not a separate taxable entity for U.S. federal and certain states purposes, and its results are included in the consolidated income tax returns of Oasis Petroleum. The provision for income taxes recorded by the Predecessor was determined as if the Predecessor was a stand-alone taxpayer for the period prior to the initial public offering on September 25, 2017.

The Predecessor's income tax expense consists of the following for the year ended December 31, 2017:

	(In thousands)
Current:	
Federal	$ 15,571
State	2,047
Total current income tax expense	17,618
Deferred:	
Federal	4,631
State	609
Total deferred income tax expense	5,240
Total income tax expense	$ 22,858

The reconciliation of income taxes calculated at the U.S. federal statutory rate to the Predecessor's effective tax rate for the year ended December 31, 2017 is as follows:

	(%)	(In thousands)
U.S. federal statutory rate	35.00 %	$ 33,392
Earnings not subject to tax subsequent to the initial public offering	(12.83)%	(12,239)
State income taxes, net of federal income tax benefit	1.81 %	1,727
Other	(0.02)%	(22)
Annual effective tax rate	23.96 %	$ 22,858

11. Commitments and Contingencies

Included below is a description of the Partnership's various future commitments as of December 31, 2019. The commitments under these arrangements are not recorded in the accompanying Consolidated Balance Sheets in accordance with GAAP. The amounts disclosed represent undiscounted cash flows on a gross basis and no inflation elements have been applied.

Volume commitment agreements. As of December 31, 2019, the Partnership had certain agreements with an aggregate requirement to either deliver or purchase a minimum quantity of approximately 13.1 million barrels of water, prior to any applicable volume credits, within specified timeframes, all of which are ten years or less.

The estimable future commitments under these volume commitment agreements as of December 31, 2019 were as follows:

	(In thousands)
2020	$ 3,600
2021	2,759
2022	876
2023	—
2024	—
Thereafter	838
Total	$ 8,073

Subsequent to December 31, 2019, the Partnership entered into new agreements to deliver, transport or purchase additional volumes of produced water within specified timeframes, all of which are ten years or less. The estimable future commitments under these volume commitment agreements were approximately $3.8 million.

Litigation. The Partnership is party to various legal and/or regulatory proceedings from time to time arising in the ordinary course of business. When the Partnership determines that a loss is probable of occurring and is reasonably estimable, the Partnership accrues an undiscounted liability for such contingencies based on its best estimate using information available at the time. The Partnership discloses contingencies where an adverse outcome may be material, or where in the judgment of management, the matter should otherwise be disclosed.

Mirada litigation. On March 23, 2017, Mirada Energy, LLC, Mirada Wild Basin Holding Company, LLC and Mirada Energy Fund I, LLC (collectively, "Mirada") filed a lawsuit against Oasis Petroleum, Oasis Petroleum North America LLC ("OPNA"), and OMS, seeking monetary damages in excess of $100 million, declaratory relief, attorneys' fees and costs (*Mirada Energy, LLC, et al. v. Oasis Petroleum North America LLC, et al.*; in the 334th Judicial District Court of Harris County, Texas; Case Number 2017-19911). Mirada asserts that it is a working interest owner in certain acreage owned and operated by Oasis Petroleum in Wild Basin. Specifically, Mirada asserts that Oasis Petroleum has breached certain agreements by: (1) failing to allow Mirada to participate in Oasis Petroleum's midstream operations in Wild Basin; (2) refusing to provide Mirada with information that Mirada contends is required under certain agreements and failing to provide information in a timely fashion; (3) failing to consult with Mirada and failing to obtain Mirada's consent prior to drilling more than one well at a time in Wild Basin; and (4) overstating the estimated costs of proposed well operations in Wild Basin. Mirada seeks a declaratory judgment that Oasis Petroleum be removed as operator in Wild Basin at Mirada's election and that Mirada be allowed to elect a new operator; certain agreements apply to Oasis Petroleum and Mirada and Wild Basin with respect to this dispute; Oasis Petroleum be required to provide all information within its possession regarding proposed or ongoing operations in Wild Basin; and Oasis Petroleum not be permitted to drill, or propose to drill, more than one well at a time in Wild Basin without obtaining Mirada's consent. Mirada also seeks a declaratory judgment with respect to Oasis Petroleum's current midstream operations in Wild Basin. Specifically, Mirada seeks a declaratory judgment that Mirada has a right to participate in Oasis Petroleum's Wild Basin midstream operations, consisting of produced and flowback water disposal, crude oil gathering and natural gas gathering and processing; that, upon Mirada's election to participate, Mirada is obligated to pay its proportionate costs of Oasis Petroleum's midstream operations in Wild Basin; and that Mirada would then be entitled to receive a share of revenues from the midstream operations and would not be charged any amount for its use of these facilities for production from the "Contract Area."

On June 30, 2017, Mirada amended its original petition to add a claim that Oasis Petroleum has breached certain agreements by charging Mirada for midstream services provided by its affiliates and to seek a declaratory judgment that Mirada is entitled to be paid its share of total proceeds from the sale of hydrocarbons received by OPNA or any affiliate of OPNA without deductions for midstream services provided by OPNA or its affiliates.

On February 2, 2018 and February 16, 2018, Mirada filed a second and third amended petition, respectively. In these filings, Mirada alleged new legal theories for being entitled to enforce the underlying contracts, and added Bighorn DevCo, Bobcat DevCo and Beartooth DevCo as defendants, asserting that these entities were created in bad faith in an effort to avoid contractual obligations owed to Mirada.

On March 2, 2018, Mirada filed a fourth amended petition that described Mirada's alleged ownership and assignment of interests in assets purportedly governed by agreements at issue in the lawsuit. On August 31, 2018, Mirada filed a fifth amended petition that added the Partnership as a defendant, asserting that it was created in bad faith in an effort to avoid contractual obligations owed to Mirada.

On July 2, 2019, Oasis Petroleum, OPNA, OMS, the Partnership, Bighorn DevCo, Bobcat DevCo and Beartooth DevCo (collectively “Oasis Entities”) counterclaimed against Mirada for a judgment declaring that Oasis Entities are not obligated to purchase, manage, gather, transport, compress, process, market, sell or otherwise handle Mirada’s proportionate share of oil and gas produced from OPNA-operated wells. The counterclaim also seeks attorney’s fees, costs and expenses.

On November 1, 2019, Mirada filed a sixth amended petition that stated that Mirada seeks in excess of $200 million in damages and asserted that OMS is an agent of OPNA and OPNA, OMS, the Partnership, Bighorn DevCo, Bobcat DevCo and Beartooth DevCo are agents of Oasis Petroleum. Mirada also changed its allegation that it may elect a new operator for the subject wells to instead allege that Mirada may remove Oasis Petroleum as operator.

On November 1, 2019, the Oasis Entities amended their counterclaim against Mirada for a judgment declaring that a provision in one of the agreements does not incorporate by reference any provisions in a certain participation agreement and joint operating agreement. The additional counterclaim also seeks attorney’s fees, costs and expenses. On the same day, the Oasis Entities filed an amended answer asserting additional defenses against Mirada’s claims.

Oasis Petroleum and the Partnership believe that Mirada’s claims are without merit, that Oasis Petroleum has complied with its obligations under the applicable agreements and that some of Mirada’s claims are grounded in agreements that do not apply to Oasis Petroleum. Oasis Petroleum filed answers denying all of Mirada’s claims and intends and continues to vigorously defend against Mirada’s claims.

Discovery is ongoing, and each of the parties has made a number of procedural filings and motions, and additional filings and motions can be expected over the course of the claim. Trial is scheduled for May 2020. Neither the Partnership nor Oasis Petroleum can predict or guarantee the ultimate outcome or resolution of such matter. If such matter were to be determined adversely to the Partnership’s or Oasis Petroleum’s interests, or if the Partnership or Oasis Petroleum were forced to settle such matter for a significant amount, such resolution or settlement could have a material adverse effect on the Partnership's business, financial condition, results of operations and cash flows. Such an adverse determination could materially impact Oasis Petroleum’s ability to operate its properties in Wild Basin or develop its identified drilling locations in Wild Basin on its current development schedule. A determination that Mirada has a right to participate in Oasis Petroleum’s midstream operations could materially reduce the interests of Oasis Petroleum and the Partnership in the Partnership’s current assets and future midstream opportunities and related revenues in Wild Basin. Under the Omnibus Agreement the Partnership entered into with Oasis Petroleum in connection with the closing of the initial public offering, Oasis Petroleum agreed to indemnify the Partnership for any losses resulting from this litigation. However, the Partnership cannot guarantee that such indemnity will fully protect the Partnership from the adverse consequences of any adverse ruling.

Solomon litigation. On or about August 28, 2019, Oasis Petroleum LLC, a wholly-owned subsidiary of Oasis Petroleum (“OP LLC”), was named as a defendant in the lawsuit styled *Andrew Solomon, on behalf of himself and those similarly situated vs. Oasis Petroleum, LLC*, pending in the United States District Court for the District of North Dakota. The lawsuit alleged violations of the federal Fair Labor Standards Act (the “FLSA”) and Title 29 of the North Dakota Century Code (“Title 29”) as the result of OP LLC’s alleged practice of paying the plaintiff and similarly situated current and former employees overtime at rates less than required by applicable law, or failing to pay for certain overtime hours worked. The lawsuit requested that: (i) its federal claims be advanced as a collective action, with a class of all operators, technicians and all other employees in substantially similar positions employed by OP LLC who were paid hourly for at least one week during the three year period prior to the commencement of the lawsuit, who worked 40 or more hours in at least one workweek and/or eight or more hours on at least one workday; and (ii) its state claims be advanced as a class action, with a class of all operators, technicians, and all other employees in substantially similar positions employed by OP LLC in North Dakota during the two year period prior to the commencement of the lawsuit, who worked 40 or more hours in at least one workweek and/or worked eight or more hours in a day on at least one workday. No motion has been filed for class certification, and the Partnership cannot predict whether such motion will be filed or a class certified.

Oasis Petroleum believes that Mr. Solomon’s claims are without merit and that OP LLC has complied with its obligations under the FLSA and Title 29. OP LLC has filed an answer denying all of Mr. Solomon’s claims and intends to vigorously defend against the claims. The Partnership cannot predict or guarantee the ultimate outcome or resolutions of such matter. If such matter were to be determined adversely to Oasis Petroleum’s interests, or if Oasis Petroleum were forced to settle such matter for a significant amount, such resolution or settlement could have a material adverse effect on the Partnership’s business, financial condition, results of operations or cash flows.

12. Equity-Based Compensation

The LTIP provides for the grant, at the discretion of the board of directors of the General Partner, of options, unit appreciation rights, restricted units, phantom units, and other unit or cash-based awards. The purpose of awards under the LTIP is to provide additional incentive compensation to individuals providing services to the Partnership, and to align the economic interests of such individuals with the interests of the Partnership's unitholders.

As of December 31, 2019, the aggregate number of common units that may be issued pursuant to any and all awards under the LTIP is equal to 2,455,408 common units, subject to adjustment due to recapitalization or reorganization, or related to forfeitures or expiration of awards, as provided under the LTIP. On January 1 of each calendar year following the adoption and prior to the expiration of the LTIP, the total number of common units that may be issued pursuant to the LTIP automatically increases by a number of common units equal to one percent of the number of common units outstanding on a fully diluted basis as of the close of business on the immediately preceding December 31 (calculated by adding to the number of common units outstanding, all outstanding securities convertible into common units on such date on an as converted basis). As a result of this adjustment, an additional 337,952 common units were reserved for issuance pursuant to awards under the LTIP on January 1, 2020.

Phantom unit awards. On October 19, 2017, the Partnership granted under its LTIP 101,500 phantom unit awards to certain employees of Oasis Petroleum who are non-employees of the Partnership. Each phantom unit represents the right to receive a cash payment equal to the fair market value of one common unit on the day prior to the date it vests. Award recipients are also entitled to distribution equivalent rights, which represent the right to receive a cash payment equal to the value of the distributions paid on one common unit between the grant date and the vesting date. The phantom units vest in equal amounts each year over a three-year period. The phantom units are accounted for as liability-classified awards since the awards will settle in cash. Under the fair value method for liability-classified awards, compensation expense is remeasured each reporting period at fair value based upon the closing price of a publicly traded common unit. Oasis Petroleum reimburses the Partnership for the cash settlement amount of these awards.

The following table summarizes information related to phantom units issued under the LTIP and held by certain employees of Oasis Petroleum for the periods presented:

	Phantom Units	Weighted Average Grant Date Fair Value per Unit
Non-vested units outstanding at December 31, 2018	58,379	$ 16.40
Granted	—	—
Vested	(22,112)	16.40
Forfeited	(14,198)	16.40
Non-vested units outstanding at December 31, 2019	22,069	$ 16.40

Equity-based compensation recorded for phantom unit awards was $0.1 million and $0.1 million as of December 31, 2019 and 2018, respectively, and is included in the Consolidated Balance Sheets in Accounts Receivable from Oasis Petroleum, for the portion reimbursed from Oasis Petroleum, and Accrued Liabilities, for the portion to be paid to award holders. The Partnership did not record any equity-based compensation expense related to these awards for the year ended December 31, 2017 because these awards were first granted during the fourth quarter of 2017. The fair value of awards vested was $0.4 million for the year ended December 31, 2019 and $0.6 million for the year ended December 31, 2018. No awards vested during the year ended December 31, 2017. The weighted average grant date fair value of phantom units granted was $16.40 per unit for the year ended December 31, 2017. No phantom units were granted under the LTIP for the years ended December 31, 2019 or 2018. Unrecognized equity-based compensation as of December 31, 2019 for all outstanding phantom unit awards was $0.4 million and will be recognized over a weighted average period of 0.9 year.

Restricted unit awards. The Partnership has granted to independent directors of the General Partner restricted unit awards under the LTIP, which vest over a one year period. These awards are accounted for as equity-classified awards since the awards will settle in common units upon vesting. Under the fair value method for equity-classified awards, equity-based compensation expense is measured at the grant date based on the fair value of the award and is recognized over the service period.

The following table summarizes information related to restricted units issued under the LTIP and held by certain directors of the General Partner for the periods presented:

	Restricted Units	Weighted Average Grant Date Fair Value per Unit
Non-vested units outstanding at December 31, 2018	17,260	$ 17.55
Granted	16,170	18.57
Vested	(17,260)	17.55
Forfeited	—	—
Non-vested units outstanding at December 31, 2019	16,170	$ 18.57

Equity-based compensation expense recorded for restricted unit awards was $0.4 million, $0.4 million and $0.1 million for the years ended December 31, 2019, 2018 and 2017, respectively, and is included in general and administrative expenses on the Consolidated Statements of Operations. The fair value of awards vested was $0.3 million for each of the years ended December 31, 2019 and 2018. No awards vested during the year ended December 31, 2017. The weighted average grant date fair value of restricted unit awards granted was $18.57 per unit, $17.55 per unit and $17.00 per unit for the years ended December 31, 2019, 2018 and 2017, respectively. Unrecognized equity-based compensation as of December 31, 2019 for all outstanding restricted unit awards was $0.01 million and will be recognized over a weighted average period of 0.1 year.

Restricted stock awards (Predecessor). Prior to the initial public offering, certain employees of Oasis Petroleum were granted restricted stock awards under its Amended and Restated 2010 Long Term Incentive Plan, the majority of which vest over a three-year period. Oasis Petroleum accounts for these awards as equity-classified awards, in accordance with GAAP. The value of restricted stock grants is based on the closing sales price of Oasis Petroleum's common stock on the date of grant, and compensation expense is recognized ratably over the requisite service period.

In accordance with its indirect shared service expense allocation from Oasis Petroleum, the Predecessor recorded equity-based compensation expense associated with these awards of approximately $1.0 million for the year ended December 31, 2017 and is included in general and administrative expenses on the Consolidated Statements of Operations. The weighted average grant date fair value of restricted stock awards granted was $14.95 per share and the fair value of awards vested was $0.8 million for the year ended December 31, 2017. As of December 31, 2019, there was no unrecognized expense associated with these awards attributable to the Partnership.

13. Partnership Equity and Distributions

On November 14, 2018, the Partnership completed a public offering of 2,300,000 common units (including 300,000 common units issued pursuant to the underwriters' option to purchase additional common units), representing limited partnership interests, at a purchase price to the public of $20.00 per common unit. Net proceeds from the offering were $44.5 million, after deducting underwriting discounts, commissions and offering costs. The Partnership used the net proceeds to fund a portion of the 2018 Dropdown Acquisition (see Note 4 — Acquisitions). This public offering was made pursuant to an effective shelf registration statement on Form S-3 filed with the SEC on October 1, 2018.

Cash distributions. On January 30, 2020, the board of directors of the General Partner declared the quarterly distribution for the fourth quarter of $0.54 per unit. In addition, the General Partner will receive a cash distribution of $1.0 million attributable to its incentive distribution rights ("IDRs") related to earnings for the fourth quarter. These distributions will be paid on February 27, 2020 to unitholders of record as of February 13, 2020.

The following table details the distributions paid in respect of each period in which the distributions were earned:

Period	Record Date	Distribution Date	Distribution per limited partner unit	Distributions		
				Limited Partners		General Partner
				Common units	Subordinated units	IDRs
				(In thousands)		
Q1 2018	May 17, 2018	May 29, 2018	$ 0.3925	$ 5,406	$ 5,397	$ —
Q2 2018	August 16, 2018	August 28, 2018	0.4100	5,649	5,638	—
Q3 2018	November 9, 2018	November 27, 2018	0.4300	5,925	5,913	—
Q4 2018	February 15, 2019	February 28, 2019	0.4500	9,020	6,188	112
Q1 2019	May 17, 2019	May 29, 2019	0.4700	9,421	6,463	238
Q2 2019	August 16, 2019	August 28, 2019	0.4900	9,822	6,738	463
Q3 2019	November 15, 2019	November 27, 2019	0.5150	10,323	7,081	745
Q4 2019	February 13, 2020	February 27, 2020	0.5400	10,833	7,425	1,027

Minimum quarterly distribution. The partnership agreement requires that all of the Partnership's available cash be distributed quarterly. Under the current cash distribution policy, the Partnership intends to distribute to the holders of common units and subordinated units on a quarterly basis at least the minimum quarterly distribution of $0.3750 per unit, or $1.50 on an annualized basis, to the extent the Partnership has sufficient cash after establishment of cash reserves and payment of fees and expenses, including payments to the General Partner and its affiliates.

Subordinated units. Oasis Petroleum owns all of the Partnership's subordinated units. The partnership agreement provides that, during the subordination period, the common units have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. No arrearages will accrue or be payable on the subordinated units.

When the subordination period ends, each outstanding subordinated unit will convert into one common unit and will thereafter participate pro rata with the other common units in distributions of available cash.

The subordination period will end on December 31, 2020 if each of the following tests are met:

- for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date, aggregate distributions from operating surplus equaled or exceeded the sum of the minimum quarterly distribution multiplied by the total number of common units and subordinated units outstanding in each quarter in each period;
- for the same three consecutive, non-overlapping four-quarter periods, the "adjusted operating surplus" (as defined in the partnership agreement) equaled or exceeded the sum of the minimum quarterly distribution multiplied by the total number of common units and subordinated units outstanding during each quarter on a fully diluted weighted average basis; and
- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Notwithstanding the foregoing, the subordination period will automatically terminate, and all of the subordinated units will convert into common units on a one-for-one basis, on the first business day after the distribution to unitholders in respect of any quarter, beginning with the quarter ended December 31, 2018, if each of the following has occurred:

- for one four-quarter period immediately preceding that date, aggregate distributions from operating surplus exceeded 150.0% of the minimum quarterly distribution multiplied by the total number of common units and subordinated units outstanding in each quarter in the period;
- for the same four-quarter period, the "adjusted operating surplus" (as defined in the Partnership's Amended and Restated Agreement of Limited Partnership) equaled or exceeded 150.0% of the sum of the minimum quarterly distribution multiplied by the total number of common and subordinated units outstanding during each quarter on a fully diluted weighted average basis, plus the related distribution on the IDRs; and
- there are no arrearages in payment of the minimum quarterly distributions on the common units.

Incentive distribution rights. The General Partner owns all of the Partnership's IDRs, which entitle it to receive increasing percentages, up to a maximum of 50.0% of the cash the Partnership distributes in excess of $0.4313 per unit per quarter. The maximum distribution of 50.0% does not include any distributions that Oasis Petroleum may receive on common units or subordinated units that it owns.

Percentage allocations of available cash from operating surplus. For any quarter in which the Partnership has distributed cash from operating surplus to the common and subordinated unitholders in an amount equal to the minimum distribution, the Partnership will distribute any additional available cash from operating surplus for that quarter among the unitholders and the IDRs holders in the following manner:

		Marginal Percentage Interest in Distributions	
	Total Quarterly Distribution Per Unit	**Unitholders**	**IDR Holders**
Minimum Quarterly Distribution	up to $0.3750	100 %	— %
First Target Distribution	above $0.3750 up to $0.4313	100 %	— %
Second Target Distribution	above $0.4313 up to $0.4688	85 %	15 %
Third Target Distribution	above $0.4688 up to $0.5625	75 %	25 %
Thereafter	above $0.5625	50 %	50 %

14. Earnings Per Limited Partner Unit

Earnings per limited partner unit is computed by dividing the respective limited partners' interest in earnings attributable to the Partnership by the weighted average number of common and subordinated units outstanding. Because there is more than one class of participating securities, the Partnership uses the two-class method when calculating earnings per limited partner unit. The classes of participating securities include common units, subordinated units and IDRs.

Diluted earnings per limited partner unit reflects the potential dilution that could occur if securities or agreements to issue common units, such as awards under the LTIP, were exercised, settled or converted into common units. When it is determined that potential common units should be included in diluted net income per limited partner unit calculation, the impact is reflected by applying the treasury stock method. There are no adjustments made to income attributable to the Partnership in the calculation of diluted earnings per limited partner unit.

The following is a calculation of the basic and diluted weighted average units outstanding for the periods presented:

	December 31,		
	2019	**2018**	**2017**
		(In thousands)	
Basic weighted average common units outstanding	20,024	14,504	13,566
Dilutive effect of restricted awards	8	15	2
Diluted weighted average common units outstanding	20,032	14,519	13,568

Net income related to the 2018 Dropdown Acquisition was recorded prospectively from the closing date. Net income related to the 2019 Delaware Acquisition was recast to prior periods, and earnings for the period prior to the effective date were allocated to the Delaware Predecessor. See Note 4 — Acquisitions for further information on these transactions.

The following table presents the calculation of earnings per limited partner unit under the two-class method:

	Year ended December 31, 2019			
	General Partner	Limited Partners		
	IDRs	Common units	Subordinated units	Total
	(In thousands, except per unit data)			
Net income attributable to OMP LP:				
Distribution declared	$ 2,472	$ 40,400	$ 27,706	$ 70,578
Undistributed earnings attributable to OMP LP	—	27,912	19,166	47,078
Net income attributable to OMP LP	$ 2,472	$ 68,312	$ 46,872	$ 117,656
Weighted average limited partner units outstanding				
Basic		20,024		
Diluted		20,032		
Net income attributable to OMP LP per limited partner unit				
Basic		$ 3.41		
Diluted		3.41		
Anti-dilutive restricted units		13		

	Year ended December 31, 2018			
	General Partner	Limited Partners		
	IDRs	Common units	Subordinated units	Total
	(In thousands, except per unit data)			
Net income attributable to OMP LP:				
Distribution declared	$ 112	$ 26,001	$ 23,134	$ 49,247
Undistributed earnings attributable to OMP LP	—	415	393	808
Net income attributable to OMP LP	$ 112	$ 26,416	$ 23,527	$ 50,055
Weighted average limited partner units outstanding				
Basic		14,504		
Diluted		14,519		
Net income attributable to OMP LP per limited partner unit				
Basic		$ 1.82		
Diluted		1.82		
Anti-dilutive restricted units		6		

	Year ended December 31, 2017			
	General Partner	Limited Partners		
	IDRs	Common units	Subordinated units	Total
	(In thousands, except per unit data)			
Net income attributable to OMP LP:				
Distribution declared	$ —	$ 5,498	$ 5,493	$ 10,991
Undistributed earnings attributable to OMP LP	—	321	326	647
Net income attributable to OMP LP	$ —	$ 5,819	$ 5,819	$ 11,638
Weighted average limited partner units outstanding				
Basic		13,566		
Diluted		13,568		
Net income attributable to OMP LP per limited partner unit				
Basic		$ 0.43		
Diluted		0.43		
Anti-dilutive restricted units		10		

15. Subsequent Events

The Partnership has evaluated the period after the balance sheet date, noting no subsequent events or transactions that required recognition or disclosure in the financial statements, other than as previously disclosed.

16. Quarterly Financial Data - Unaudited

The Partnership’s results of operations, by quarter, for the years ended December 31, 2019 and 2018 were as follows:

	Year Ended December 31, 2019			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per unit data)			
Revenues(1)	$ 93,852	$ 100,403	$ 103,550	$ 112,386
Operating income(1)	48,383	54,580	61,732	68,077
Net income(1)	44,414	50,246	57,120	63,451
Net income attributable to OMP LP	21,543	26,198	31,436	38,479
Earnings per limited partner unit - Basic and Diluted				
Common units	$ 0.63	$ 0.76	$ 0.91	$ 1.11

(1) Retrospectively adjusted for the transfer of net assets between entities under common control. See Note 4 — Acquisitions.

	Year Ended December 31, 2018							
	First Quarter		Second Quarter		Third Quarter		Fourth Quarter	
	(In thousands, except per unit data)							
Revenues[1]	$	61,693	$	67,106	$	72,105	$	72,866
Operating income[1]		32,032		38,068		39,416		40,830
Net income[1]		31,770		37,868		39,160		38,954
Net income attributable to OMP LP		9,954		12,444		12,376		15,281
Earnings per limited partner unit - Basic and Diluted								
Common units	$	0.36	$	0.45	$	0.45	$	0.54

(1) Retrospectively adjusted for the transfer of net assets between entities under common control. See Note 4 — Acquisitions.

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

None.

Item 9A. Controls and Procedures

Evaluation of disclosure controls and procedures. As required by Rule 13a-15(b) of the Exchange Act we have evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer ("CEO"), our principal executive officer, and our Chief Financial Officer ("CFO"), our principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2019. Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our CEO and CFO as appropriate, to allow timely decisions regarding required disclosure. Based on the evaluation, our CEO and CFO have concluded that our disclosure controls and procedures were effective at December 31, 2019 at a reasonable assurance level.

Management's annual report on internal control over financial reporting. The SEC, as required by Section 404 of the Sarbanes-Oxley Act, adopted rules requiring every public company that files reports with the SEC to include a management report on such company's internal control over financial reporting in its annual report. Section 404 of the Sarbanes-Oxley Act also requires the independent registered public accounting firm of every public company that files reports with the SEC to attest to the effectiveness of internal control over financial reporting.

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

As of December 31, 2019, management assessed the effectiveness of our internal control over financial reporting. In making this assessment, management, including our CEO or CFO, used the criteria set forth by the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on this assessment, management concluded that our internal control over financial reporting was effective as of December 31, 2019.

This Annual Report on Form 10-K does not include a report of our independent registered public accounting firm's assessment regarding internal control over financial reporting as permitted by the transition period established by SEC rules applicable to newly public companies. We will remain an "emerging growth company" for up to five full fiscal years following the initial public offering, although we will lose such status sooner if we have more than $1.07 billion of revenues in a fiscal year, become a large accelerated filer or issue more than $1.0 billion of non-convertible debt cumulatively over a three-year period.

Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) that occurred during the quarter ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Management of Oasis Midstream Partners LP

We are managed and operated by the board of directors and executive officers of our General Partner, OMP GP LLC. Our General Partner is indirectly controlled by Oasis Petroleum. All of our officers and certain of our directors are also officers and/or directors of Oasis Petroleum. Neither our General Partner nor its board of directors will be elected by our unitholders and none will be subject to re-election in the future. As of December 31, 2019, OMS Holdings, a wholly-owned subsidiary of Oasis Petroleum, owns an aggregate 67.5% limited partner interest in us and a 91% controlling interest in our General Partner and has the right to appoint our General Partner's entire board of directors, including at least three independent directors meeting the independence standards established by Nasdaq. Our unitholders are not entitled to directly or indirectly participate in our management or operations. Our General Partner owes certain contractual duties to our unitholders as well as a fiduciary duty to its owners.

Our General Partner has seven directors. Nasdaq does not require a listed publicly traded partnership, such as ours, to have a majority of independent directors on the board of directors of our General Partner or to establish a compensation committee or a nominating committee. However, our General Partner is required to have an audit committee of at least three members, and all of its members are required to meet the independence and experience standards established by Nasdaq and the Exchange Act. Oasis Petroleum, through its ownership of OMS Holdings, appointed three members of the audit committee to the board of directors of our General Partner. Please read "Committees of the Board of Directors — Audit Committee" below.

In evaluating director candidates, Oasis Petroleum assesses whether a candidate possesses the integrity, judgment, knowledge, experience, skill and expertise that are likely to enhance the board's ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of committees of the board to fulfill their duties.

All of the executive officers of our General Partner listed below allocate their time between managing our business and affairs and the business and affairs of Oasis Petroleum. The amount of time that our executive officers devote to our business and the business of Oasis Petroleum varies in any given year based on a variety of factors. Our executive officers devote as much time to the management of our business and affairs as is necessary for the proper conduct of our business and affairs.

Oasis Petroleum provides customary management and general administrative services to us pursuant to a services and secondment agreement. We reimburse Oasis Petroleum at cost for its direct expenses incurred on behalf of us and a proportionate amount of its indirect expenses incurred on behalf of us, including, but not limited to, compensation expenses. However, Oasis Petroleum may elect, in its sole discretion, to reimburse us for the cost of awards under the LTIP. Neither our General Partner nor Oasis Petroleum will receive any management fee or other compensation. Our partnership agreement does not set a limit on the amount of expenses for which our General Partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our General Partner by its affiliates. Please read "Item 11. Executive Compensation" and "Item 13. Certain Relationships and Related Transactions, and Director Independence."

Executive Officers and Directors of Our General Partner

The following table shows information for the executive officers and directors of our General Partner as of December 31, 2019. Directors hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Executive officers serve at the discretion of the board. Some of the directors and executive officers of our General Partner also serve as executive officers and/or directors of Oasis Petroleum.

Name	Age	Position With Our General Partner
Thomas B. Nusz	60	Chairman of the Board
Taylor L. Reid	57	Chief Executive Officer and Director
Michael H. Lou	45	President and Director
Nickolas J. Lorentzatos	50	Executive Vice President, General Counsel and Corporate Secretary and Director
Richard N. Robuck	45	Senior Vice President and Chief Financial Officer
Matthew Fitzgerald	62	Director
Phillip D. Kramer	63	Director
Harry N. Pefanis	62	Director

Thomas B. Nusz is the Chairman of the board of directors of our General Partner. He has served as Oasis Petroleum's Director and Chief Executive Officer since March 2007. He has also served as Oasis Petroleum's President until January 1, 2014, and has 38 years of experience in the oil and gas industry. From April 2006 to February 2007, Mr. Nusz managed his personal investments, developed the business plan for Oasis Petroleum LLC and secured funding for Oasis Petroleum. He was previously a Vice President with Burlington Resources Inc., a formerly publicly traded oil and gas E&P company or, together with its predecessors, Burlington, and served as President International Division (North Africa, Northwest Europe, Latin America and China) from January 2004 to March 2006, as Vice President Acquisitions and Divestitures from October 2000 to December 2003 and as Vice President Strategic Planning and Engineering from July 1998 to September 2000 and Chief Engineer for substantially all of such period. He was instrumental in Burlington's expansion into the Western Canadian Sedimentary Basin from 1999 to 2002. From September 1985 to June 1998, Mr. Nusz held various operations and managerial positions with Burlington in several regions of the United States, including the Permian Basin, the San Juan Basin, the Black Warrior Basin, the Anadarko Basin, onshore Gulf Coast and Gulf of Mexico. Mr. Nusz was an engineer with Mobil Oil Corporation and for Superior Oil Company from June 1982 to August 1985. He is a current member of the National Petroleum Council, an advisory committee to the Secretary of Energy of the United States. Mr. Nusz holds a Bachelor of Science in Petroleum Engineering from Mississippi State University.

The board believes that Mr. Nusz's considerable operational and financial experience brings important and valuable skills to the board of directors.

Taylor L. Reid is the Chief Executive Officer and Director of our General Partner. He has served as Oasis Petroleum's Director, President and Chief Operating Officer since January 1, 2014. He served as Oasis Petroleum's Director, Executive Vice President and Chief Operating Officer (or in similar capacities) since Oasis Petroleum's inception in March 2007 and has 35 years of experience in the oil and gas industry. From November 2006 to February 2007, Mr. Reid worked with Mr. Nusz to form the business plan for Oasis Petroleum LLC and secure funding for Oasis Petroleum. He previously served as Asset Manager Permian and Panhandle Operations with ConocoPhillips from April 2006 to October 2006. Prior to joining ConocoPhillips, he served as General Manager Latin America and Asia Operations with Burlington from March 2004 to March 2006 and as General Manager Corporate Acquisitions and Divestitures from July 1998 to February 2004. From March 1986 to June 1998, Mr. Reid held various operations and managerial positions with Burlington in several regions of the continental United States, including the Permian Basin, the Williston Basin and the Anadarko Basin. He was instrumental in Burlington's expansion into the Western Canadian Sedimentary Basin from 1999 to 2002. Mr. Reid holds a Bachelor of Science in Petroleum Engineering from Stanford University.

The board believes that Mr. Reid's considerable operational experience brings important and valuable skills to the board of directors.

Michael H. Lou is the President and Director of our General Partner. He has served as Oasis Petroleum's Executive Vice President and Chief Financial Officer since August 2011. Mr. Lou served as Oasis Petroleum's Senior Vice President Finance (or similar capacities) from September 2009 to August 2011 and has 23 years of experience in the oil and gas industry. Prior to joining us, Mr. Lou was an independent contractor from January 2009 to August 2009. From February 2008 to December 2008, he served as the Chief Financial Officer of Giant Energy Ltd., a private oil and gas management company; from July 2006 to December 2008 he served as Chief Financial Officer of XXL Energy Corp., a publicly listed Canadian oil and gas company; and from August 2008 to December 2008, he served as Vice President Finance of Warrior Energy N.V., a publicly listed Canadian oil and gas company. From October 2005 to July 2006, Mr. Lou was a Director for Macquarie Investment Bank. Prior to joining Macquarie, Mr. Lou was a Vice President for First Albany Investment Banking from 2004 to 2006. From 1999 to 2004, Mr. Lou held positions of increasing responsibility, most recently as a Vice President, for Bank of America's investment banking group. From 1997 to 1999, Mr. Lou was an analyst for Merrill Lynch's investment banking group. Mr. Lou holds a Bachelor of Science in Electrical Engineering from Southern Methodist University.

The board believes that Mr. Lou's considerable operational and financial experience brings important and valuable skills to the board of directors.

Nickolas J. Lorentzatos is the Executive Vice President, General Counsel and Corporate Secretary and Director of our General Partner. He has served as Oasis Petroleum's Executive Vice President, General Counsel and Corporate Secretary since January 1, 2014. Mr. Lorentzatos served as Oasis Petroleum's Senior Vice President, General Counsel and Corporate Secretary from September 2010 to December 31, 2013, and has 19 years of experience in the oil and gas industry and 24 years practicing law. He previously served as Senior Counsel with Targa Resources from July 2007 to September 2010. From April 2006 to July 2007, he served as Senior Counsel to ConocoPhillips. Prior to the merger of Burlington Resources Inc. and ConocoPhillips which became effective in 2006, he served as Counsel and Senior Counsel to Burlington since August 1999. From September 1995 to August 1999, he was an associate with Bracewell & Patterson, LLP. Mr. Lorentzatos holds a Bachelor of Arts from Washington and Lee University, a Juris Doctor from the University of Houston, and a Masters of Business Administration from the University of Texas at Austin.

The board believes that Mr. Lorentzatos' considerable operational and legal experience brings important and valuable skills to the board of directors.

Richard N. Robuck is the Senior Vice President and Chief Financial Officer of our General Partner. He has served as Oasis Petroleum's Senior Vice President Finance and Treasurer since January 2017. Previously, Mr. Robuck served as Vice President Finance and Treasurer (or similar capacities) since April 2010. Mr. Robuck began his career 22 years ago in the oil and gas industry at Bank of America in their Energy Group. Prior to joining Oasis Petroleum, Mr. Robuck was VP - Finance and Investments at Southern Ute Alternative Energy from October 2008 until April 2010. From July 2001 to October 2008, he served in various financial capacities at Grande Communications, a private telecommunications company in Austin, Texas, serving as VP-Finance from April 2005 through October 2008. Mr. Robuck holds a Bachelor of Business Administration from The University of Texas at Austin and a Master of Business Administration from Rice University.

Phillip D. Kramer is a Director of our General Partner. Mr. Kramer served as Executive Vice President of Plains All American Pipeline, L.P. ("PAA") from November 2008 until his retirement in April 2017 and previously served as Executive Vice President and Chief Financial Officer from PAA's formation in 1998 until November 2008. In addition, he was Executive Vice President and Chief Financial Officer of Plains Resources Inc. from May 1998 to May 2001, and previously served Plains Resources as Senior Vice President / Vice President and Chief Financial Officer from 1992 to 1997. Mr. Kramer is a past Certified Public Accountant and was previously on the board of directors of the general partner of Petrologistics LP from 2012 to 2014 where he was elected to serve as the chairman of the audit committee of the board. He is presently on the board of directors of Earthstone Energy Inc. and the Board of Advisors of the University of Oklahoma Price College of Business. He holds a degree in accounting from the University of Oklahoma.

The board believes that Mr. Kramer's considerable operational and financial experience brings important and valuable skills to the board of directors.

Matthew Fitzgerald is a Director and the Chair of the Audit Committee of our General Partner. Mr. Fitzgerald has been a private investor since July 2013. From 2009 until July 2013, Mr. Fitzgerald served as President of Total Choice Communications LLC, a wireless retailer in Houston, Texas. Mr. Fitzgerald retired from Grant Prideco, Inc., following its merger with National Oilwell Varco in 2008. He had served as Senior Vice President and Chief Financial Officer and as Treasurer beginning in February 2007. Mr. Fitzgerald held the positions of Executive Vice President, Chief Financial Officer, and Treasurer of Veritas DGC. Mr. Fitzgerald also served as Vice President and Controller for BJ Services Company. He previously served on the Board of Directors of Rosetta Resources, Inc. from 2009 until its merger with Noble Energy in 2015 and currently serves on the Board of Directors of Independence Contract Drilling and NCS Multistage Inc. Mr. Fitzgerald began his career as a Certified Public Accountant with Ernst & Whinney. He holds a BSBA and Masters in Accounting from the University of Florida**.**

The board believes that Mr. Fitzgerald's considerable operational, accounting and financial experience brings important and valuable skills to the board of directors.

Harry N. Pefanis is a Director of our General Partner. Mr. Pefanis has served as a director of PAA GP Holdings LLC since February 2017. Mr. Pefanis is President and Chief Commercial Officer of Plains All American GP LLC, the general partner of Plains All American Pipeline, L.P. Mr. Pefanis has held the position of President of PAA and its predecessors since 1988. Mr. Pefanis joined Plains Resources (which formerly owned 100% of PAA's GP interest) in 1983. Prior to joining Plains Resources in 1983, Mr. Pefanis was an auditor for the national accounting firm of Price Waterhouse & Co. He is a director of the American Petroleum Institute (API), and the Association of Oil Pipelines and is currently serving on the Executive Committee as past Chair of the Association of Oil Pipelines. He also served on the New York Mercantile Exchange's Crude Oil Advisory Committee from 1996 through 2003. Mr. Pefanis serves as a director of the Memorial Hermann Foundation; and serves on the Advisory Board of the Price College of Business at the University of Oklahoma. Mr. Pefanis has a BBA in accounting from the University of Oklahoma.

The board believes that Mr. Pefanis's considerable operational, accounting and financial experience brings important and valuable skills to the board of directors.

Committees of the Board of Directors

The board of directors of our General Partner has a standing audit committee and a conflicts committee. We do not expect that we will have a compensation committee, but rather that our board of directors will approve equity grants to directors and employees.

Audit Committee

Rules implemented by Nasdaq and SEC require us to have an audit committee comprised of at least three directors who meet the independence and experience standards established by Nasdaq and the Exchange Act. As required by the rules of the SEC and listing standards of Nasdaq, the audit committee consists solely of independent directors. Our audit committee consists of Matthew Fitzgerald, Phillip D. Kramer and Harry N. Pefanis, who are independent under the rules of the SEC. SEC rules also require that a public company disclose whether or not its audit committee has an "audit committee financial expert" as a member. An "audit committee financial expert" is defined as a person who, based on his or her experience, possesses the attributes outlined in such rules. Our board of directors has determined that Matthew Fitzgerald qualifies as an “audit committee financial expert.”

This committee oversees, reviews, acts on and reports on various auditing and accounting matters to our board of directors, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants and our accounting practices. In addition, the audit committee oversees our compliance programs relating to legal and regulatory requirements. We have adopted an audit committee charter defining the committee’s primary duties in a manner consistent with the rules of the SEC and Nasdaq, which can be found on our corporate website.

Conflicts Committee

At least one independent member of the board of directors of our General Partner will serve on a conflicts committee to review specific matters that the board believes may involve conflicts of interest and determines to submit to the conflicts committee for review. The conflicts committee will determine if the resolution of the conflict of interest is adverse to the interest of the partnership. There is no requirement that our General Partner seek the approval of the conflicts committee for the resolution of any conflict. The members of the conflicts committee may not be officers or employees of our General Partner or directors, officers or employees of its affiliates, including Oasis Petroleum, and must meet the independence and experience standards established by the Nasdaq and the Exchange Act to serve on an audit committee of a board of directors, along with other requirements in our partnership agreement. Any matters approved by the conflicts committee will be conclusively deemed to be approved by us and all of our partners and not a breach by our General Partner of any duties it may owe us or our unitholders.

Non-Management Executive Sessions and Unitholder Communications

The non-management directors meet regularly in executive session, and Mr. Pefanis acts as presiding director in such sessions. Unitholders and interested parties can communicate directly with non-management directors by mail in care of the General Counsel and Corporate Secretary at Oasis Midstream Partners LP, 1001 Fannin St., Suite 1500, Houston, Texas 77002. Such communications should specify the intended recipient or recipients. Commercial solicitations or communications will not be forwarded.

Meetings and Other Information

During the fiscal year ended December 31, 2019, our board of directors had five meetings and our audit committee had four meetings. Each of our directors attended all of the meetings of the board of directors and committees on which such director served. Our Corporate Governance Guidelines, Code of Business Conduct and Ethics, Financial Code of Ethics, and Audit Committee Charter can be found on the Partnership’s website at www.oasismidstream.com. These documents provide the framework for our corporate governance. Our Financial Code of Ethics applies to our principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions.

Item 11. Executive Compensation

Introduction

Our General Partner has the sole responsibility for conducting our business and for managing our operations, and its board of directors and executive officers make decisions on our behalf. The executive officers of our General Partner are employed by Oasis Petroleum and manage the day-to-day affairs of our business. References to "our Named Executive Officers" and "our directors" refer to the executive officers and directors of our General Partner.

We are currently considered an emerging growth company under the JOBS Act. As such, the compensation-related sections of this document provide the information required to comply with the reduced compensation disclosure requirements applicable to emerging growth companies.

In accordance with such rules, we are required to provide a Summary Compensation Table and an Outstanding Equity Awards at Fiscal Year End Table, as well as limited narrative disclosures. Further, our reporting obligations extend only to our principal executive officer and our two most highly compensated executive officers (other than our principal executive officer) determined by reference to total compensation for 2019 as reported in the Summary Compensation Table below.

For 2019, our Named Executive Officers were:

Name	Principal Executive Position(s)
Taylor L. Reid	Chief Executive Officer
Michael H. Lou	President
Nickolas J. Lorentzatos	Executive Vice President, General Counsel and Corporate Secretary

Our Named Executive Officers allocate their time between managing our business and affairs and the business and affairs of Oasis Petroleum. Our Named Executive Officers intend, however, to devote as much time to the management of our business and affairs as is necessary for the proper conduct of our business and affairs.

We and our General Partner had no material assets or operations until the closing of the initial public offering on September 25, 2017. Accordingly, our General Partner did not accrue any obligations with respect to compensation expenses for our directors and our Named Executive Officers for any periods prior to the closing of the initial public offering. Because our Named Executive Officers are employed by Oasis Petroleum, compensation of our Named Executive Officers, other than any awards granted under the LTIP are determined and paid by Oasis Petroleum and reimbursed by us to Oasis Petroleum with respect to the portion of our Named Executive Officers' professional time spent managing our business in accordance with the terms of the Services and Secondment Agreement. Please read "Item 13. Certain Relationships and Related Transactions, and Director Independence — Agreements with Affiliates in Connection with the Transactions — Services and Secondment Agreement" for more information. The members of the board of directors of our General Partner administer and make all decisions regarding awards granted to our executive officers under the LTIP.

Summary Compensation Table

The following table summarizes the total compensation for our Named Executive Officers for services rendered to us during the fiscal years ended December 31, 2019 and December 31, 2018. The amounts reported in the table below reflect only the compensation reimbursed by us to Oasis Petroleum under the Services and Secondment Agreement with respect to our Named Executive Officers for the period presented, which we believe most accurately reflects the total compensation paid to the Named Executive Officers for services provided to us during 2019 and 2018. For the avoidance of doubt, the amounts reported in the table below do not reflect the aggregate compensation received by these individuals for all services to Oasis Petroleum and its affiliates, including us and our General Partner. The amounts reported in the table are intended only to represent the compensation received by our Named Executive Officers during the stated period for services rendered to us.

Name and Principal Position	Year	Salary ($)[1]	Stock Awards ($)[2]	Non-Equity Incentive Plan Compensation ($)[3]	All Other Compensation ($)[4]	Total ($)
Taylor L. Reid	2019	78,538	459,250	54,900	2,871	595,559
Chief Executive Officer	2018	25,200	119,549	25,200	947	170,896
Michael H. Lou	2019	77,456	407,279	55,080	3,303	543,118
President	2018	20,160	95,639	20,160	929	136,888
Nickolas J. Lorentzatos	2019	68,595	288,586	39,015	3,184	399,380
Executive Vice President, General Counsel and Corporate Secretary	2018	17,693	63,513	14,280	861	96,347

(1) Amounts reflect the portion of the base salary paid to our Named Executive Officers by Oasis Petroleum that was reimbursable by us under the Services and Secondment Agreement for the fiscal year indicated.
(2) Amounts reflect the portion of the aggregate grant date fair value, computed in accordance with FASB ASC Topic 718, of restricted stock awards, performance share units, and phantom units granted to our Named Executive Officers by Oasis Petroleum under Oasis Petroleum's Amended and Restated 2010 Long-Term Incentive Plan that was reimbursable by us under the Services and Secondment Agreement for the year ended December 31, 2019. For fiscal year 2019, the grant date fair value for the restricted stock awards is based on the closing price of Oasis Petroleum's common stock on January 17, 2019, the grant date for those awards, which was $6.63 per share. The grant date fair value for the performance share units granted on January 17, 2019 was calculated based on the initial number of performance share units granted at a weighted average grant date fair value price per unit of $6.80, as computed using a Monte Carlo simulation model in accordance with FASB ASC Topic 718. Assuming that the highest level of the performance condition is achieved, the portion of the grant date fair value for these awards that would be reimbursable by us under the Services and Secondment Agreement would have been: for Mr. Reid - $506,769, Mr. Lou - $453,115, and Mr. Lorentzatos - $321,067. The grant date fair value for the phantom unit awards is based on the closing price of the Partnership's common units on January 17, 2019, the grant date for those awards, which was $18.57 per common unit.
(3) Amounts reflect annual performance-based cash incentives earned for the fiscal years indicated and paid by Oasis Petroleum based on performance against metrics established by Oasis Petroleum, as will be described in the Oasis Petroleum proxy statement for the 2020 Annual Meeting of Stockholders, in the section entitled "Compensation Discussion and Analysis—Annual Executive Compensation Decisions—Annual Performance-Based Cash Incentives," and were reimbursable by us under the Services and Secondment Agreement for the fiscal year indicated.
(4) Amounts reported in the "All Other Compensation" column reflect the portion of such compensation which was paid to our Named Executive Officers by Oasis Petroleum, and was reimbursable by us under the Services and Secondment Agreement for the fiscal year indicated.

Outstanding Equity Awards at Fiscal Year-End

We did not grant awards under our LTIP to any of our Named Executive Officers in 2019, and our Named Executive Officers did not have any equity awards outstanding under our LTIP as of December 31, 2019. However, a portion of the value of the equity awards granted to our Named Executive Officers by Oasis Petroleum is reimbursable by us pursuant to the terms of the Services and Secondment Agreement. As such, the following table sets forth information concerning the approximate portion of the outstanding equity awards as of December 31, 2019 that were granted by Oasis Petroleum and are reimbursable by us. For additional information regarding the outstanding equity awards granted by Oasis Petroleum to our Named Executive Officers in connection with their services to us and Oasis Petroleum, please see the section titled "Executive Compensation-Outstanding Equity Awards at Fiscal Year-End" in the Oasis Petroleum proxy statement for the 2020 Annual Meeting of Stockholders, which we expect will be filed in March 2020.

	Restricted Stock Awards		Phantom Unit Awards		PSUs	
Name	Number of Shares of Stock That Have Not Vested(1)	Market Value of Shares of Stock That Have Not Vested(2)	Number of Shares of Stock That Have Not Vested(3)	Market Value of Shares of Stock That Have Not Vested(4)	Equity Incentive Plan Awards: Number of Unearned Shares that Have Not Vested(5)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares that Have Not Vested(6)
Taylor L. Reid	28,468	$92,804	2,217	$36,776	30,808	$100,433
Michael H. Lou	20,289	$66,144	1,552	$25,745	22,343	$72,839
Nickolas J. Lorentzatos	14,248	$46,450	1,099	$18,236	15,677	$51,108

(1) The shares subject to the 2018 Annual Award vest in three substantially equal annual installments. The first 1/3 tranche vested on January 24, 2019. The second tranche vested on January 24, 2020 and the final tranche will vest on January 24, 2021. The shares subject to the 2019 Annual Award vest in three substantially equal annual installments. The first 1/3 tranche vested on January 17, 2020. The second tranche will vest on January 17, 2021 and the final tranche will vest on January 17, 2022.

(2) This column reflects the closing price of Oasis Petroleum's common stock on December 31, 2019 (the last trading day of fiscal year 2019), which was $3.26, multiplied by the number of outstanding shares of restricted stock.

(3) The phantom units subject to the 2019 Annual Award will vest in three substantially equal annual installments on the day following the date that the Partnership pays its quarterly distribution for the quarter ending December 31, 2019, 2020, and 2021.

(4) This column reflects the closing price of the Partnership's common units on December 31, 2019 (the last trading day of fiscal year 2019), which was $16.59, multiplied by the number of outstanding phantom units.

(5) The designated performance cycle for the 2018 PSU awards each commenced on January 24, 2018 and end on January 23, 2020, 2021, and 2022. One third of the performance share units awarded may become earned during each performance cycle. The designated performance cycle for the 2019 PSU awards each commenced on January 17, 2019 and end on January 23, 2020, 2021, and 2022. One third of the performance share units awarded may become earned during each performance cycle. The tables reflects the total outstanding performance share unit awards multiplied by the performance level percentage indicated below, which in accordance with SEC rules is the next higher performance level for each award that exceeds 2019 performance. The number of shares reported in the table above are shown for PSUs granted:

- On January 24, 2018, at a performance level of 80%
- On January 17, 2019, at a performance level of 71%

(6) This column reflects the closing price of Oasis Petroleum's common stock on December 31, 2019 (the last trading day of fiscal year 2019), which was $3.26, multiplied by the number of outstanding PSUs.

Additional Narrative Disclosure

We are managed and operated by our General Partner. Neither we nor our General Partner employ any of the individuals who serve as executive officers of our General Partner and are responsible for managing our business. All of the executive officers of our General Partner are employed and compensated by Oasis Petroleum or one of its subsidiaries. All of the executive officers responsible for managing our day-to-day affairs are also current officers of Oasis Petroleum and have responsibilities to both us and Oasis Petroleum and allocate their time between managing our business and managing the business of Oasis Petroleum. The amount of time that our executive officers devote to our business and the business of Oasis Petroleum varies in any given year based on a variety of factors. Our executive officers devote as much time to the management of our business and affairs as is necessary for the proper conduct of our business and affairs.

Since all of our executive officers are employed by Oasis Petroleum or one of its subsidiaries, the responsibility and authority for compensation-related decisions for our executive officers will reside with Oasis Petroleum's board of directors or compensation committee. Any such compensation decisions are not subject to any approvals by the board of directors of our General Partner or any committees thereof. However, all determinations with respect to awards that may be granted to our executive officers, key employees and independent directors under the LTIP will be made by the board of directors of our General Partner. Our General Partner does not currently have a compensation committee, but our General Partner may establish a compensation committee in the future.

Compensation Paid by Us

Except with respect to any awards that may be granted under the LTIP, our Named Executive Officers do not receive any compensation paid directly by us. In accordance with the terms of our partnership agreement and our Services and Secondment Agreement, we reimburse Oasis Petroleum for compensation-related expenses attributable to the portion of the executive officer's time dedicated to providing services to us, including expenses for salary, bonus, incentive compensation and other amounts paid. However, Oasis Petroleum may elect, in its sole discretion, to reimburse us for the cost of awards under the LTIP. Please read "Item 13. Certain Relationships and Related Transactions, and Director Independence — Agreements with Affiliates in Connection with the Transactions — Services and Secondment Agreement." We will not bear any portion of the cost of the Class B Units representing limited liability company interests in our General Partner that may be granted by our General Partner.

We did not grant awards under our LTIP to any of our Named Executive Officers in 2019. For additional information regarding the compensation paid to our Named Executive Officers and included in our Summary Compensation Table, please read the Compensation Discussion and Analysis section and accompanying compensation tables of the Oasis Petroleum proxy statement for the 2020 Annual Meeting of Stockholders, which we expect will be filed in March 2020.

We do not sponsor any plans or programs that provide for retirement benefits and do not have any agreements with our Named Executive Officers that provide for payment to them in the event of their resignation, retirement, or other termination or change of control.

For information regarding Oasis Petroleum programs and agreements that provide for retirement or severance payments to our Named Executive Officers, including the treatment of restricted stock units and performance share units granted under Oasis Petroleum's Amended and Restated 2010 Long-Term Incentive Plan, please see the Compensation Discussion and Analysis section of the Oasis Petroleum proxy statement for the 2020 Annual Meeting of Stockholders, which we expect will be filed in March 2020.

Compensation at Oasis Petroleum

The executive officers of our General Partner, as well as the employees of Oasis Petroleum who provide services to us, participate in employee benefit plans and arrangements sponsored by Oasis Petroleum, including plans that may be established in the future. Certain executive officers and employees who provide services to us currently hold awards under Oasis Petroleum's equity incentive plan. Further, certain of our executive officers currently have employment agreements with Oasis Petroleum. These compensation arrangements are described in greater detail in Oasis Petroleum's definitive proxy statement on Schedule 14A for its 2020 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission.

Long Term Incentive Plan

The board of directors of our General Partner adopted on September 11, 2017, effective as of September 20, 2017, the LTIP.

The LTIP is administered by the board of directors of our General Partner, which we refer to as the "committee" for purposes of this summary. The committee will administer the LTIP pursuant to its terms and all applicable state, federal, or other rules or laws. The committee will have the power to determine to whom and when awards will be granted, determine the amount of awards (measured in cash or our common units), proscribe and interpret the terms and provisions of each award agreement (the terms of which may vary), accelerate the vesting provisions associated with an award, delegate duties under the LTIP and execute all other responsibilities permitted or required under the LTIP. In the event that the committee is not comprised of "non-employee directors" within the meaning of Rule 16b-3 under the Exchange Act, the full board of directors or a subcommittee of two or more nonemployee directors will administer all awards granted to individuals that are subject to Section 16 of the Exchange Act.

As of December 31, 2019, the aggregate number of common units that may be issued pursuant to any and all awards under the LTIP was equal to 2,455,408 common units, subject to adjustment due to recapitalization or reorganization, or related to forfeitures or expiration of awards, as provided under the LTIP. On January 1 of each calendar year following the adoption and prior to the expiration of the LTIP, the total number of common units that may be issued pursuant to the LTIP shall increase by a number of common units equal to one percent (1%) of the number of common units outstanding on a fully diluted basis as of the close of business on the immediately preceding December 31 (calculated by adding to the number of common units outstanding, all outstanding securities convertible into common units on such date on an as converted basis).

If any common units subject to any award are not issued or transferred, or cease to be issuable or transferable for any reason, including (but not exclusively) because units are withheld or surrendered in payment of taxes or any exercise or purchase price relating to an award or because an award is forfeited, terminated, expires unexercised, is settled in cash in lieu of common units, or is otherwise terminated without a delivery of units, those common units will again be available for issue, transfer, or exercise pursuant to awards under the LTIP, to the extent allowable by law. Common units to be delivered pursuant to awards under our LTIP may be common units acquired by our General Partner in the open market, from any other person, directly from us, or any combination of the foregoing. There is no limitation on the number of awards that may be granted or paid in cash.

Compensation Committee Interlocks and Insider Participation

As previously discussed, our General Partner's board of directors is not required to maintain, and does not maintain, a compensation committee. During 2019, all compensation decisions with respect to our Named Executive Officers were made by Oasis Petroleum.

Compensation Policies and Practices as They Relate to Risk Management

We do not have any employees. We are managed and operated by the directors and officers of our General Partner, who are employees of Oasis Petroleum and perform services on our behalf. For 2019, we did not have any compensation policies or practices that need to be assessed or evaluated for the effect on our operations. For an analysis of any risks arising from Oasis Petroleum's compensation policies and practices, please read the Oasis Petroleum proxy statement for the 2020 Annual Meeting of Stockholders, which we expect will be filed in March 2020.

Compensation Committee Report

As previously discussed, neither we nor our General Partner has a compensation committee. Additionally, as an emerging growth company, we are not required to include a Compensation Discussion and Analysis section in this Form 10-K. However, the board of directors of our General Partner has discussed with management the information set forth above and based on this review and discussion has approved it for inclusion in this Form 10-K.

Members of the Board of Directors:

- Matthew Fitzgerald
- Phillip D. Kramer

- Harry N. Pefanis
- Nickolas J. Lorentzatos
- Michael H. Lou
- Thomas B. Nusz
- Taylor L. Reid

Director Compensation

The officers of our General Partner or of Oasis Petroleum who also serve as directors of our General Partner do not receive additional compensation for their service as members of the board of directors of our General Partner. Directors of our General Partner who are not officers of our General Partner or of Oasis Petroleum (non-employee directors) receive cash and equity-based compensation for their services as directors of our General Partner.

Our General Partner's non-employee director compensation program consists of the following:

- A cash retainer of $70,000 per year, payable quarterly;
- An additional cash retainer, payable quarterly if such non-employee director serves as the chairperson of a committee ($20,000 per year for the chairperson of the audit committee and $15,000 per year for the chairperson of the conflicts committee);
- An additional cash retainer, payable quarterly if such non-employee directors serves as a member of a committee ($4,750 per year for the members of the audit committee and $10,000 per year for the members of the conflicts committee);
- An additional payment of $2,000 for each board meeting attended in excess of five meetings per year;
- An additional payment of $2,000 for each committee meeting attended as a member in excess of five meetings per year; and
- Annual equity based compensation with an aggregate grant date value of approximately $100,000 in the form of restricted units which vest one year following the grant date, subject to the terms of the LTIP and the restricted unit award agreement pursuant to which such award is granted.

Each member of the board of directors of our General Partner will be reimbursed for certain travel and miscellaneous expenses in accordance with the policies of our General Partner. In addition, each member of the board of directors of our General Partner will be indemnified for his or her actions associated with being a director to the fullest extent permitted under Delaware law.

The following table provides information regarding the compensation earned by our non-employee directors during the year ended December 31, 2019.

Name	Fees Earned or Paid in Cash (1)	Equity Awards(2)	Total
Phillip D. Kramer	$106,000	$100,092	$206,092
Matthew D. Fitzgerald	106,000	100,092	206,092
Harry N. Pefanis	91,000	100,092	191,092

(1) Includes an annual cash retainer, board and committee meeting fees, and committee chair fees for each non-employee director during fiscal year 2019.

(2) The value of equity awards compensation reflects the aggregate grant date fair value of these awards computed in accordance with FASB ASC Topic 718. The grant date fair value is computed based upon the closing price of our common units on the respective date of grant, which was $18.57 per common unit on January 17, 2019. As of December 31, 2019, Messrs. Kramer, Fitzgerald and Pefanis each held 5,390 outstanding restricted units, which vested in full on January 17, 2020.

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

The following table sets forth the beneficial ownership of our common and subordinated units as of February 19, 2020 held by:

- each unitholder know by us to beneficial hold more than 5% or more of our outstanding units;
- each director and named executive officer of our General Partner; and
- all of our directors and executive officers as a group.

In addition, our General Partner owns a non-economic general partner interest in us and all of our IDRs.

The amounts and percentage of our common units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote or to direct the voting of such security, or "investment power," which includes the power to dispose of or to direct the disposition of such security. Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all common units shown as beneficially owned by them, subject to community property laws where applicable. Unless otherwise noted, the address for each beneficial owner listed below is 1001 Fannin Street, Suite 1500, Houston, Texas 77002.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned(1)	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Common and Subordinated Units Beneficially Owned
Oasis Petroleum(2)(3)	9,075,000	45.2%	13,750,000	100%	67.5%
Thomas B. Nusz	8,000	¬	—	—	¬
Taylor L. Reid	20,000	¬	—	—	¬
Michael H. Lou	25,000	¬	—	—	¬
Nickolas J. Lorentzatos	5,900	¬	—	—	¬
Richard N. Robuck	7,500	¬	—	—	¬
Matthew Fitzgerald	27,763	¬	—	—	¬
Phillip D. Kramer	38,763	¬	—	—	¬
Harry N. Pefanis	40,840	¬			¬
All directors and executive officers as a group (8 persons)	173,766	¬	—	—	¬

(1) Percentage of total common units beneficially owned based on 20,061,366 common units outstanding as of February 19, 2020.

(2) Under Oasis Petroleum's amended and restated certificate of incorporation and bylaws, the voting and disposition of any of our common or subordinated units held by Oasis Petroleum is controlled by the board of directors of Oasis Petroleum. The board of directors of Oasis Petroleum, which acts by majority approval, is comprised of Thomas B. Nusz, Taylor L. Reid, William J. Cassidy, John E. Hagale, Michael McShane, Bobby S. Shackouls and Paula D. Polito. Each of the members of Oasis Petroleum's board of directors disclaims beneficial ownership of any of our units held by Oasis Petroleum.

(3) As reported on Schedule 13D filed with the SEC on November 28, 2018 by OMS Holdings, Oasis Petroleum LLC and Oasis Petroleum. Oasis Petroleum is a public company and owns 100% of the equity interests of Oasis Petroleum LLC. Oasis Petroleum LLC owns 100% of the equity interests of OMS Holdings. OMS Holdings is the managing member of our General Partner. These entities have shared voting power and shared dispositive power with respect to 22,825,000 units (including 9,075,000 common units and 13,750,000 subordinated units).

* Less than 1%

The following table sets forth the number of shares of common stock of Oasis Petroleum owned by each of the directors and named executive officers of our General Partner and all directors and named executive officers of our General Partner as a group as of February 19, 2020:

Name of Beneficial Owner	Shares Beneficially Owned	Percentage of Shares Beneficially Owned
Thomas B. Nusz	2,045,553	¬
Taylor L. Reid[(1)]	2,077,448	¬
Michael H. Lou	580,937	¬
Nickolas J. Lorentzatos	406,012	¬
Richard N. Robuck	172,333	¬
Matthew Fitzgerald	—	—
Phillip D. Kramer	—	—
Harry N. Pefanis	—	—
All directors and named executive officers as a group (8 persons)	5,282,283	¬

(1) Mr. Reid has sole voting power over 1,529,260 of these shares and shared voting power over 548,188 of these shares. The 548,188 shares are held by West Bay Partners, Ltd., a limited partnership formed for family investment purposes. The sole general partner of West Bay Partners, Ltd., a Texas limited liability company, is controlled by Mr. Reid and his wife, and the limited partners of West Bay consist of Mr. Reid, his immediate family members and trusts formed for their benefit.

* Less than 1%

Securities Authorized for Issuance under Equity Compensation Plans

The following table summarizes information regarding the number of common units that are available for issuance under our LTIP as of December 31, 2019:

Plan Category	Number of Securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column a) (c)
Equity compensation plans approved by security holders	—	—	2,410,212
Equity compensation plans not approved by security holders	—	—	—
Total	—	—	2,410,212

(1) Pursuant to the terms of the LTIP, on January 1 of each calendar year occurring after the effective date and prior to the expiration of the LTIP, the total number of common units reserved and available for issuance under the LTIP shall increase by a number of common units equal to one percent (1%) of the number of common units outstanding on a fully diluted basis as of the close of business on the immediately preceding December 31 (calculated by adding to the number of common units outstanding and all outstanding securities convertible into common units on such date on an as converted basis).

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

As of December 31, 2019, Oasis Petroleum owns 9,075,000 common units and 13,750,000 subordinated units representing an aggregate 67.5% limited partner interest in us. Oasis Petroleum owns a 91% controlling interest in and appoints all the directors of our General Partner, which owns a non-economic general partner interest in us and all of the IDRs.

Delaware Acquisition

On November 1, 2019, the Partnership entered into an agreement with Oasis Petroleum, pursuant to which Oasis Petroleum agreed to assign to Panther DevCo certain crude oil gathering and produced and flowback water gathering and disposal assets in the Delaware Basin in exchange for cash consideration of approximately $24.9 million. The Partnership funded the cash consideration with borrowings under the Revolving Credit Facility.

Distributions and Payments to our General Partner and Its Affiliates

The following summarizes the distributions and payments made, or to be made, by us to our General Partner and its affiliates in connection with the formation, ongoing operation and liquidation of us. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Formation Stage

The aggregate consideration received by our General Partner and its affiliates, including Oasis Petroleum, for the contribution of our initial assets:

- 5,125,000 common units;
- 13,750,000 subordinated units;
- all of our incentive distribution rights;
- the non-economic general partner interest; and
- an initial cash distribution of $132.1 million from the Partnership.

Operational Stage

Distributions of cash to our General Partner and its affiliates, including Oasis Petroleum:

We will generally make cash distributions 100% to our unitholders, including affiliates of our General Partner. In addition, if distributions from operating surplus exceed the minimum quarterly distribution and other higher target distribution levels, Oasis Petroleum, or the initial holder of the IDRs, will be entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target distribution level.

Assuming we have sufficient cash to pay the full minimum quarterly distribution on all of our outstanding common units and subordinated units for four quarters, our General Partner and its affiliates (including Oasis Petroleum) would receive an annual distribution of approximately $34.2 million on their units, based upon the number of units outstanding as of February 19, 2020.

Payments to our General Partner and its affiliates:

Oasis Petroleum will provide customary management and general administrative services to us. We will reimburse Oasis Petroleum at cost for its direct expenses incurred on behalf of us and a proportionate amount of its indirect expenses incurred on behalf of us, including, but not limited to, compensation expenses. Our General Partner will not receive a management fee or other compensation for its management of our partnership, but we will reimburse our General Partner and its affiliates for all direct and indirect expenses they incur and payments they make on our behalf, including payments made to Oasis Petroleum for customary management and general administrative services. Our partnership agreement and Services and Secondment Agreement do not set a limit on the amount of expenses for which our General Partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our General Partner by its affiliates. However, Oasis Petroleum may elect, in its sole discretion, to reimburse us for the cost of awards under the LTIP. Our partnership agreement provides that our General Partner will determine the expenses that are allocable to us. Please read "—Agreements with Affiliates in Connection with the Transactions—Services and Secondment Agreement."

Withdrawal or removal of our General Partner:

If our General Partner withdraws or is removed, its non-economic general partner interest and its IDRs and those of its affiliates will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation Stage

Upon our liquidation, the partners, including our General Partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements with Affiliates in Connection with the Transactions

We and other parties entered into the various agreements that effected the transactions in connection with the initial public offering, including the vesting of assets in, and the assumption of liabilities by, us and our subsidiaries, and the application of the proceeds from the initial public offering. While not the result of arm's-length negotiations, we believe the terms of all of our initial agreements with Oasis Petroleum and its affiliates are, and specifically intend the rates to be, generally no less favorable to either party than those that could have been negotiated with unaffiliated parties with respect to similar services. All of the transaction expenses incurred in connection with these transactions, including the expenses associated with transferring assets into our subsidiaries, were paid for with the proceeds from the initial public offering. Additionally, we have entered into certain agreements with Oasis Petroleum, as described in more detail below.

Registration Rights Agreement

On September 25, 2017, in connection with the closing of the initial public offering, the Partnership entered into a registration rights agreement with Oasis Petroleum (the "Registration Rights Agreement") pursuant to which the Partnership may be required to register the sale of the (i) common units issued to Oasis Petroleum, (ii) the Partnership's subordinated units and (iii) common units issuable upon conversion of subordinated units pursuant to the terms of our partnership agreement (collectively, the "Registrable Securities") it holds. Under the Registration Rights Agreement, Oasis Petroleum has the right to request that the Partnership register the sale of Registrable Securities held by it and the right to require the Partnership to make available shelf registration statements permitting sales of Registrable Securities into the market from time to time over an extended period, subject to certain limitations. Pursuant to the Registration Rights Agreement and our partnership agreement, the Partnership may be required to undertake a future public or private offering and use the proceeds (net of underwriting or placement agency discounts, fees and commissions, as applicable) to redeem an equal number of common units from Oasis Petroleum. In addition, the Registration Rights Agreement gives Oasis Petroleum "piggyback" registration rights under certain circumstances. The Registration Rights Agreement also includes provisions dealing with indemnification and contribution and allocation of expenses. All of the Registrable Securities held by Oasis Petroleum and any permitted transferee will be entitled to these registration rights.

Omnibus Agreement

On September 25, 2017, in connection with the closing of the initial public offering, the Partnership entered into an omnibus agreement (the "Omnibus Agreement") with Oasis Petroleum and certain of its affiliates, pursuant to which:

- Oasis Petroleum granted the Partnership a ROFO with respect to (i) its retained interests in each of Bobcat DevCo and Beartooth DevCo and (ii) any other midstream assets that Oasis Petroleum or any successor to Oasis Petroleum builds with respect to its acreage at the time of the initial public offering and elects to sell in the future, which ROFO converts into a ROFR upon a change of control of Oasis Petroleum;
- Oasis Petroleum provided the Partnership with a license to use certain Oasis Petroleum-related names and trademarks in connection with the Partnership's operations; and
- Oasis Petroleum agreed to indemnify the Partnership for certain environmental and other liabilities, including certain liabilities related to the Mirada litigation (as described in the Omnibus Agreement, the "Mirada Litigation"), and the Partnership agreed to indemnify Oasis Petroleum for certain environmental and other liabilities related to the Partnership's assets to the extent Oasis Petroleum is not required to indemnify the Partnership.

The maximum liability of Oasis Petroleum for its indemnification obligations under the Omnibus Agreement will not exceed $15 million and Oasis Petroleum will not have any obligation under this indemnification until the Partnership's aggregate losses exceed $100,000; provided that Oasis Petroleum's indemnification obligations with respect to the Mirada Litigation are not subject to the aggregate limit or deductible. Oasis Petroleum will have no indemnification obligations with respect to environmental claims made as a result of additions to or modifications of environmental laws enacted or promulgated after the closing of the initial public offering and its indemnification obligations (other than with respect to the Mirada Litigation) will terminate on the third anniversary of the closing of the initial public offering.

The Partnership has agreed to indemnify Oasis Petroleum against all losses, including environmental liabilities, related to the operation of the Partnership's assets after the closing of the initial public offering, to the extent Oasis Petroleum is not required to indemnify the Partnership for such losses.

The initial term of the Omnibus Agreement will be ten years from the closing of the initial public offering and will thereafter automatically extend from year-to-year unless terminated by the Partnership or the General Partner. Oasis Petroleum may terminate the Omnibus Agreement in the event that it ceases to be an affiliate of the Partnership and may also terminate the Omnibus Agreement if the Partnership fails to pay amounts due under the agreement in accordance with its terms. Additionally, both the ROFO and the ROFR in the Omnibus Agreement will terminate in the event Oasis Petroleum elects to sell the General Partner to a third party (other than in connection with a change of control of Oasis Petroleum). The Omnibus Agreement may only be assigned by a party with the other parties' consent.

Services and Secondment Agreement

On September 25, 2017, in connection with the closing of the initial public offering, the Partnership entered into a 15-year services and secondment agreement with Oasis Petroleum (the "Services and Secondment Agreement"), pursuant to which, Oasis Petroleum will, or will cause its affiliates to, perform centralized corporate, general and administrative services for the Partnership. Oasis Petroleum will also second to the Partnership certain of its employees to operate, construct, manage and maintain the Partnership's assets. The Services and Secondment Agreement requires the Partnership to reimburse Oasis Petroleum for direct general and administrative expenses incurred by Oasis Petroleum for the provision of the above services. Additionally, the Partnership will reimburse Oasis Petroleum for compensation and certain other expenses paid to employees of Oasis Petroleum that are seconded to the Partnership and who spend time managing and operating the Partnership's business. The expenses of executive officers and non-executive employees will be allocated to the Partnership based on the amount of time spent managing the Partnership's business and operations. The reimbursements to the General Partner and Oasis Petroleum will be made prior to cash distributions to holders of the Partnership's common units.

Commercial Agreements

We have commercial agreements with Oasis Petroleum with an initial term of 15 years for the provision of midstream services.

Under our commercial agreements with Oasis Petroleum and its wholly-owned subsidiaries in the Williston Basin, we provide (i) gas gathering, compression, processing and gas lift services; (ii) crude gathering, stabilization, blending and storage services; (iii) produced and flowback water gathering and disposal services; and (iv) freshwater supply and distribution services. In addition, we provide crude transportation services pursuant to the FERC-regulated crude transportation services agreement that we became a party to in connection with the initial public offering, which has up to 75,000 barrels per day of operating capacity and firm capacity for committed shippers.

Under our commercial agreements with Oasis Petroleum and its wholly-owned subsidiaries in the Delaware Basin, we provide (i) crude gathering services and (ii) produced and flowback water gathering and disposal services.

Procedures for Review, Approval and Ratification of Transactions with Related Persons

In connection with the initial public offering, the board of directors of our General Partner adopted policies for the review, approval and ratification of transactions with related persons. The board also adopted a written code of business conduct and ethics, under which our directors are required to bring to the attention of our chief executive officer or the board any conflict or potential conflict of interest that may arise between the director or any affiliate of the director, on the one hand, and us or our General Partner on the other. The resolution of any such conflict or potential conflict should, at the discretion of the board in light of the circumstances, be determined by a majority of the disinterested directors. In determining whether to approve or ratify a transaction with a related party, the board of directors of our General Partner would take into account, among other factors it deems appropriate, (1) whether the transaction is on terms no less favorable than terms generally available to an unaffiliated third party under the same or similar circumstances, (2) the extent of the related person's interest in the transaction and (3) whether the interested transaction is material to the Partnership. Our partnership agreement contains detailed provisions regarding the resolution of conflicts of interest, as well as the standard of care the board of directors of our General Partner must satisfy in doing so.

If a conflict or potential conflict of interest arises between our General Partner or its affiliates, on the one hand, and us or our unitholders, on the other hand, the resolution of any such conflict or potential conflict would be addressed by the board of directors of our General Partner in accordance with the provisions of our partnership agreement. Such a conflict of interest may arise, for example, in connection with negotiating and approving the acquisition of any assets from our sponsor, including in connection with our ROFO or ROFR, as applicable, under the Omnibus Agreement. At the discretion of the board in light of the circumstances, the resolution may be determined by the board in its entirety or by a conflicts committee meeting the definitional requirements for such a committee under our partnership agreement.

We expect to have the opportunity to acquire additional assets from Oasis Petroleum, our sponsor, in the future, including in connection with our ROFO or ROFR, as applicable, provided in the Omnibus Agreement. Our sponsor or other affiliates of our General Partner are free to offer properties to us on terms they deem acceptable. Under our code of business conduct and ethics, the board of directors of our General Partner (or the conflicts committee, if the board of directors delegates the necessary authority to the conflicts committee) is free to accept or reject any such offers and to negotiate any terms it deems acceptable to us and that the board of directors of our General Partner or the conflicts committee will decide the appropriate value of any assets offered to us by affiliates of our General Partner. In making such determination of value, the board of directors of our General Partner or the conflicts committee will be permitted to consider any factors they determine in good faith to consider.

We expect the board of directors or the conflicts committee will consider a number of economic, operational and market factors in its determination of value.

Upon our adoption of our code of business conduct and ethics, any executive officer is required to avoid conflicts of interest unless approved by the board of directors of our General Partner. The code of business conduct and ethics was adopted in connection with the closing of the initial public offering.

Director Independence

The information appearing under “Item 10. Directors, Executive Officers and Corporate Governance**”** is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

The table below sets forth the aggregate fees billed by PricewaterhouseCoopers LLP, the Partnership's independent registered public accounting firm for the years ended December 31, 2019 and December 31, 2018.

	Year Ended December 31,	
	2019	2018
	(In thousands)	
Audit Fees	$ 550	$ 679
Tax Fees	349	302
All Other Fees	—	—
Total(1)	$ 899	$ 981

(1) The Partnership's Pre-Approval of Audit, Audit-Related, Tax and Permissible Non-Audit Services Policy is summarized in this Annual Report on Form 10-K. See "Policy for Approval of Audit and Permitted Non-Audit Services" below. In 2019, all of these services were pre-approved by the Audit Committee of our General Partner in accordance with its pre-approval policy.

Policy for Approval of Audit and Permitted Non-Audit Services

Before the independent registered public accounting firm is engaged by us or our subsidiaries to render audit or non-audit services, the audit committee must pre-approve the engagement. Audit committee pre-approval of audit and non-audit services is not required if the engagement for the services is entered into pursuant to pre-approval policies and procedures established by the audit committee. The chairman of the audit committee has the authority to grant pre-approvals, provided such approvals are within the pre-approval policy and presented to the audit committee at a subsequent meeting.

PART IV

Item 15. Exhibits, Financial Statement Schedules

a. The following documents are filed as a part of this Annual Report on Form 10-K or incorporated herein by reference:

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

(3) Exhibits:

The following documents are included as exhibits to this report:

Exhibit No.	Description of Exhibit
2.1	Contribution Agreement, dated November 7, 2018, between Oasis Midstream Partners LP, OMS Holdings LLC, Oasis Midstream Services LLC, OMP GP LLC, OMP Operating LLC and, for certain limited purposes set forth therein, Oasis Petroleum Inc. (incorporated herein by reference to Exhibit 2.1 to the Form 8-K filed by the Partnership on November 8, 2018).
3.1	Certificate of Limited Partnership of Oasis Midstream Partners LP (incorporated herein by reference to Exhibit 3.1 to the Form S-1 filed by the Partnership on May 12, 2017).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Oasis Midstream Partners LP (incorporated herein by reference to Exhibit 3.2 to the Form S-1 filed by the Partnership on May 12, 2017).
3.3	Amended and Restated Agreement of Limited Partnership of Oasis Midstream Partners LP, dated September 25, 2017, by and between OMP GP LLC, as the general partner, and OMS Holdings LLC, as the organizational limited partner (incorporated herein by reference to Exhibit 3.1 to the Form 8-K filed by the Partnership on September 29, 2017).
3.4	Certificate of Formation of OMP GP LLC (incorporated herein by reference to Exhibit 3.4 to the Form S-1 filed by the Partnership on May 12, 2017.)
3.5	Certificate of Amendment to Certificate of Formation of OMP GP LLC (incorporated herein by reference to Exhibit 3.5 to the Amendment No. 2 to Form S-1 filed by the Partnership on May 30, 2017).
3.6	Amended and Restated Limited Liability Company Agreement of OMP GP LLC (incorporated herein by reference to Exhibit 3.6 to the Amendment No. 2 to Form S-1 filed by the Partnership on May 30, 2017.)
4.1(a)	Description of Registrant's Securities Registered Under Section 12 of the Exchange Act.
10.1	Contribution Agreement, dated as of September 25, 2017, by and among Oasis Midstream Partners LP, Oasis Petroleum LLC, OMS Holdings LLC, Oasis Midstream Services LLC, OMP GP LLC and OMP Operating LLC (incorporated herein by reference to Exhibit 10.1 to the Form 8-K filed by the Partnership on September 29, 2017).
10.2	Omnibus Agreement, dated as of September 25, 2017, by and among Oasis Midstream Partners LP, Oasis Petroleum Inc., Oasis Petroleum LLC, OMS Holdings LLC, Oasis Midstream Services LLC, OMP GP LLC and OMP Operating LLC (incorporated herein by reference to Exhibit 10.2 to the Form 8-K filed by the Partnership on September 29, 2017).
10.3#	Gas Gathering, Compression, Processing and Gas Lift Agreement, dated as of September 25, 2017, by and among Oasis Midstream Partners LP, Oasis Petroleum North America LLC, Oasis Petroleum Marketing LLC and Oasis Midstream Services LLC (incorporated herein by reference to Exhibit 10.3 to the Form 8-K filed by the Partnership on September 29, 2017).
10.4#	Crude Oil Gathering, Stabilization, Blending and Storage Agreement, dated as of September 25, 2017, by and among Oasis Midstream Partners LP, Oasis Petroleum North America LLC, Oasis Petroleum Marketing LLC and Oasis Midstream Services LLC (incorporated herein by reference to Exhibit 10.4 to the Form 8-K filed by the Partnership on September 29, 2017).
10.5#	Produced and Flowback Water Gathering and Disposal Agreement - Wild Basin, dated as of September 25, 2017, by and among Oasis Midstream Partners LP, Oasis Petroleum North America LLC and Oasis Midstream Services LLC (incorporated herein by reference to Exhibit 10.5 to the Form 8-K filed by the Partnership on September 29, 2017).

10.6#	Produced and Flowback Water Gathering and Disposal Agreement - Beartooth Area, dated as of September 25, 2017, by and among Oasis Midstream Partners LP, Oasis Petroleum North America LLC and Oasis Midstream Services LLC (incorporated herein by reference to Exhibit 10.6 to the Form 8-K filed by the Partnership on September 29, 2017).
10.7#	Freshwater Purchase and Sales Agreement, dated as of September 25, 2017, by and among Oasis Midstream Partners LP, Oasis Petroleum North America LLC and Oasis Midstream Services LLC (incorporated herein by reference to Exhibit 10.7 to the Form 8-K filed by the Partnership on September 29, 2017).
10.8#	Crude Oil Transportation Services Agreement, dated May 9, 2016, by and between Oasis Midstream Services LLC and Oasis Petroleum Marketing LLC (incorporated herein by reference to Exhibit 10.8 to the Form S-1/A filed by the Partnership on May 17, 2017).
10.9#	Amendment #1 and Assignment Agreement, dated as of September 25, 2017, by and among Oasis Midstream Partners LP, Oasis Petroleum Marketing LLC and Oasis Midstream Services LLC (incorporated herein by reference to Exhibit 10.8 to the Form 8-K filed by the Partnership on September 29, 2017).
10.10	Registration Rights Agreement, dated as of September 25, 2017, by and between Oasis Midstream Partners LP and OMS Holdings Inc. (incorporated herein by reference to Exhibit 10.9 to the Form 8-K filed by the Partnership on September 29, 2017).
10.11	Revolving Credit Agreement, dated as of September 25, 2017, by and among Oasis Midstream Partners LP, as parent, OMP Operating LLC, as borrower, and Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.10 to the Form 8-K filed by the Partnership on September 29, 2017).
10.12	Services and Secondment Agreement, dated as of September 25, 2017, by and between Oasis Midstream Partners LP and Oasis Petroleum Inc. (incorporated herein by reference to Exhibit 10.11 to the Form 8-K filed by the Partnership on September 29, 2017).
10.13	Amended and Restated Limited Liability Company Agreement of Bighorn DevCo LLC, dated as of September 25, 2017, by and between OMP Operating LLC, as the managing member, and Oasis Midstream Services LLC, as a member (incorporated herein by reference to Exhibit 10.12 to the Form 8-K filed by the Partnership on September 29, 2017).
10.14	Amended and Restated Limited Liability Company Agreement of Bobcat DevCo LLC, dated as of September 25, 2017, by and between OMP Operating LLC, as the managing member, and Oasis Midstream Services LLC, as a member (incorporated herein by reference to Exhibit 10.13 to the Form 8-K filed by the Partnership on September 29, 2017).
10.15	Amended and Restated Limited Liability Company Agreement of Beartooth DevCo LLC, dated as of September 25, 2017, by and between OMP Operating LLC, as the member, and Oasis Midstream Services LLC, as the original member (incorporated herein by reference to Exhibit 10.14 to the Form 8-K filed by the Partnership on September 29, 2017).
10.16†	Indemnification Agreement, dated as of September 25, 2017, by and between Oasis Midstream Partners LP and Thomas B. Nusz (incorporated herein by reference to Exhibit 10.15 to the Form 8-K filed by the Partnership on September 29, 2017).
10.17†	Indemnification Agreement, dated as of September 25, 2017, by and between Oasis Midstream Partners LP and Taylor L. Reid (incorporated herein by reference to Exhibit 10.16 to the Form 8-K filed by the Partnership on September 29, 2017).
10.18†	Indemnification Agreement, dated as of September 25, 2017, by and between Oasis Midstream Partners LP and Michael H. Lou (incorporated herein by reference to Exhibit 10.17 to the Form 8-K filed by the Partnership on September 29, 2017).
10.19†	Indemnification Agreement, dated as of September 25, 2017, by and between Oasis Midstream Partners LP and Richard N. Robuck (incorporated herein by reference to Exhibit 10.18 to the Form 8-K filed by the Partnership on September 29, 2017).
10.20†	Indemnification Agreement, dated as of September 25, 2017, by and between Oasis Midstream Partners LP and Nickolas J. Lorentzatos (incorporated herein by reference to Exhibit 10.19 to the Form 8-K filed by the Partnership on September 29, 2017).
10.21†	Indemnification Agreement, dated as of September 25, 2017, by and between Oasis Midstream Partners LP and Phillip D. Kramer (incorporated herein by reference to Exhibit 10.20 to the Form 8-K filed by the Partnership on September 29, 2017).

10.22†	Indemnification Agreement, dated as of September 25, 2017, by and between Oasis Midstream Partners LP and Matthew D. Fitzgerald (incorporated herein by reference to Exhibit 10.21 to the Form 8-K filed by the Partnership on September 29, 2017).
10.23†	Oasis Midstream Partners LP 2017 Long Term Incentive Plan (incorporated herein by reference to Exhibit 4.4 to the Form S-8 filed by the Partnership on September 25, 2017).
10.24†	Form of Restricted Unit Award Agreement (incorporated herein by reference to Exhibit 4.5 to the Form S-8 filed by the Partnership on September 25, 2017).
10.25†	Form of Restricted Unit Award Grant Notice (incorporated herein by reference to Exhibit 4.6 to the Form S-8 filed by the Partnership on September 25, 2017).
10.26	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of Bobcat DevCo LLC, dated as of November 7, 2017, by and between OMP Operating LLC, as the managing member, and Oasis Midstream Services LLC, as a member (incorporated herein by reference to Exhibit 10.25 to the Form 10-Q filed by the Partnership on November 9, 2017).
10.27	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of Beartooth DevCo LLC, dated as of November 7, 2017, by and between OMP Operating LLC, as the managing member, and Oasis Midstream Services LLC, as a member (incorporated herein by reference to Exhibit 10.26 to the Form 10-Q filed by the Partnership on November 9, 2017).
10.28	Indemnification Agreement, dated July 5, 2018, between Oasis Midstream Partners LP and Mr. Harry N. Pefanis (incorporated herein by reference to Exhibit 10.1 to the Form 10-Q filed by the Partnership on August 7, 2018).
10.29	First Amendment to Credit Agreement, dated as of August 27, 2018 among Oasis Midstream Partners, LP, as Parent, OMP Operating LLC, as Borrower, the Other Credit Parties party to thereto, Wells Fargo Banks, N.A., as Administrative Agent and the Lenders thereto (incorporated herein by reference to Exhibit 10.1 to the Form 10-Q filed by the Partnership on November 6, 2018).
10.30	Second Amendment to Credit Agreement, dated as of May 6, 2019 among Oasis Midstream Partners LP, as Parent, OMP Operating LLC, as Borrower, the Other Credit Parties party thereto, Wells Fargo Bank, N.A., as Administrative Agent and the Lenders thereto (incorporated herein by reference to Exhibit 10.3 to the Form 10-Q filed by the Partnership on May 8, 2019).
10.31	Third Amendment to Credit Agreement, dated as of August 16, 2019 among Oasis Midstream Partners LP, as Parent, OMP Operating LLC, as Borrower, the Other Credit Parties party thereto, Wells Fargo Bank, N.A., as Administrative Agent and the Lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Form 10-Q filed by the Partnership on November 6, 2019).
10.32	Second Amended and Restated Limited Liability Company Agreement of Bobcat DevCo LLC, dated as of February 22, 2019, by and between OMP Operating LLC, as the managing member, and Oasis Midstream Services LLC, as a member (incorporated herein by reference to Exhibit 10.1 to the Form 8-K filed by the Partnership on February 28, 2019).
10.33	Second Amended and Restated Limited Liability Company Agreement of Beartooth DevCo LLC, dated as of February 22, 2019, by and between OMP Operating LLC, as the managing member, and Oasis Midstream Services LLC, as a member (incorporated herein by reference to Exhibit 10.2 to the Form 8-K filed by the Partnership on February 28, 2019).
10.34(a)	Limited Liability Company Agreement of Panther DevCo LLC, dated as of May 9, 2019.
10.35##	Crude Oil Gathering Agreement by and among Oasis Petroleum Permian LLC, Oasis Petroleum Marketing LLC and Panther DevCo LLC, dated as of November 1, 2019 (incorporated herein by reference to Exhibit 10.2 to the Form 10-Q filed by the Partnership on November 6, 2019).
10.36##	Produced Water Gathering and Disposal Agreement by and between Oasis Petroleum Permian LLC and Panther DevCo LLC, dated as of November 1, 2019 (incorporated herein by reference to Exhibit 10.3 to the Form 10-Q filed by the Partnership on November 6, 2019).
21.1(a)	List of Subsidiaries of Oasis Midstream Partners LP
23.1(a)	Consent of PricewaterhouseCoopers LLP
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.

32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
101.INS(a)	XBRL Instance Document.
101.SCH(a)	XBRL Schema Document.
101.CAL(a)	XBRL Calculation Linkbase Document.
101.DEF(a)	XBRL Definition Linkbase Document.
101.LAB(a)	XBRL Labels Linkbase Document.
101.PRE(a)	XBRL Presentation Linkbase Document.
101(a)	The following financial information from Oasis Midstream Partners LP's Annual Report on Form 10-K for the year ended December 31, 2019, formatted in Inline XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Changes in Equity, (iv) Consolidated Statements of Cash Flows and (v) Notes to the Consolidated Financial Statements.
104(a)	Cover Page Interactive Data File - the cover page interactive data file does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.

Confidential treatment has been granted for certain portions thereof pursuant to a Confidential Treatment Request filed with the SEC. Such provisions have been filed separately with the SEC.

Certain information has been excluded from this exhibit because it is both (i) not material and (ii) would likely cause competitive harm to the registrant if publicly disclosed.

† Compensatory plan or arrangement.

(a) Filed herewith.

(b) Furnished herewith.

Item 16. Form 10-K Summary

None.

SIGNATURES

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

Oasis Midstream Partners LP
By: OMP GP LLC, its general partner

Date: February 26, 2020

By: */s/ Taylor L. Reid*
Taylor L. Reid,
Chief Executive Officer and Director

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title (Positions with OMP GP LLC)	Date
/s/ Taylor L. Reid Taylor L. Reid	Chief Executive Officer and Director (Principal Executive Officer)	February 26, 2020
/s/ Richard N. Robuck Richard N. Robuck	Senior Vice President and Chief Financial Officer (Principal Accounting Officer and Principal Financial Officer)	February 26, 2020
/s/ Thomas B. Nusz Thomas B. Nusz	Chairman of the Board of Directors	February 26, 2020
/s/ Michael H. Lou Michael H. Lou	President and Director	February 26, 2020
/s/ Nickolas J. Lorentzatos Nickolas J. Lorentzatos	Executive Vice President and General Counsel and Corporate Secretary and Director	February 26, 2020
/s/ Matthew Fitzgerald Matthew Fitzgerald	Director	February 26, 2020
/s/ Phillip D. Kramer Phillip D. Kramer	Director	February 26, 2020
/s/ Harry N. Pefanis Harry N. Pefanis	Director	February 26, 2020

GLOSSARY OF TERMS

Barrel: One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to crude oil, NGLs or other liquid hydrocarbons.

Blowout: An uncontrolled flow of reservoir fluids into the wellbore, and sometimes catastrophically to the surface. A blowout may consist of produced water, crude oil, natural gas or a mixture of these. Blowouts can occur in all types of E&P operations, not just during drilling operations. If reservoir fluids flow into another formation and do not flow to the surface, the result is called an underground blowout. If the well experiencing a blowout has significant open-hole intervals, it is possible that the well will bridge over (or seal itself with rock fragments from collapsing formations) down-hole and intervention efforts will be averted.

Bo: Barrel of crude oil.

Boe: Barrels of crude oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of crude oil.

Boepd: Barrel of crude oil equivalent per day.

Bopd: Barrels of crude oil per day.

Bow: Barrels of water.

Bowpd: Barrels of water per day.

British thermal unit or BTU: The quantity of heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Completion: A generic term used to describe the assembly of down-hole tubulars and equipment required to enable safe and efficient production from an crude oil or natural gas well. The point at which the completion process begins may depend on the type and design of the well.

EPA: United States Environmental Protection Agency.

Expansion capital expenditures: Expansion capital expenditures are cash expenditures to acquire additional interests in our midstream assets and to construct new midstream infrastructure and those expenditures incurred in order to extend the useful lives of our assets, reduce costs, increase revenues or increase system throughput or capacity from current levels, including well connections that increase existing system operating capacity, operating income or revenue. Examples of expansion capital expenditures include the acquisition of additional interests in our DevCos, capital contributions to Bobcat DevCo that increase our percentage interest ownership in Bobcat DevCo and the construction, development or acquisition of additional midstream assets, in each case, to the extent such capital expenditures are expected to increase, over the long term, system operating capacity, operating income or revenue. In the future, if we make acquisitions that increase system operating capacity, operating income or revenue, the associated capital expenditures may also be considered expansion capital expenditures.

FERC: Federal Energy Regulatory Commission.

Field: The general area encompassed by one or more crude oil or natural gas reservoirs or pools that are located on a single geologic feature, that are otherwise closely related to the same geologic feature (either structural or stratigraphic).

Flushwater: Freshwater used to flush out existing wells in order to prevent downhole scaling.

Hydraulic fracturing: A stimulation treatment routinely performed on crude oil and natural gas wells in low-permeability reservoirs. Specially engineered fluids are pumped at high pressure and rate into the reservoir interval to be treated, causing a vertical fracture to open. The wings of the fracture extend away from the wellbore in opposing directions according to the natural stresses within the formation. Proppant, such as grains of sand of a particular size, is mixed with the treatment fluid to keep the fracture open when the treatment is complete. Hydraulic fracturing creates high-conductivity communication with a large area of formation and bypasses any damage that may exist in the near-wellbore area.

Hydrocarbon: An organic compound containing only carbon and hydrogen.

Maintenance capital expenditures: Maintenance capital expenditures are cash expenditures (including expenditures for the construction or development of new capital assets or the replacement, improvement or expansion of existing capital assets) made to maintain, over the long term, system operating capacity, operating income or revenue. Examples of maintenance capital expenditures are expenditures to repair, refurbish and replace pipelines, to maintain equipment reliability, integrity and safety and to comply with environmental laws and regulations. In addition, we designate a portion of our capital expenditures to connect new wells to maintain gathering throughput as maintenance capital expenditures to the extent such capital expenditures are necessary to maintain, over the long term, system operating capacity, operating income or revenue. Cash expenditures made solely for investment purposes will not be considered maintenance capital expenditures.

MBo: One thousand barrels of crude oil.

MBoe: One thousand barrels of crude oil equivalent.

MBoepd: One thousand barrels of crude oil equivalent per day.

MMBoe: One million barrels of crude oil equivalent.

Mscf: One thousand standard cubic feet.

MMscfpd: One million standard cubic feet per day.

natural gas: Hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane and other gases.

NDIC: North Dakota Industrial Commission.

NGLs: Natural gas liquids, which consist primarily of ethane, propane, isobutane, normal butane and natural gasoline.

Oil: Crude oil and condensate.

Pd: Per day

Plug: A down-hole packer assembly used in a well to seal off or isolate a particular formation for testing, acidizing, cementing, etc.; also a type of plug used to seal off a well temporarily while the wellhead is removed.

Proppant: Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

Resource Play: Accumulation of hydrocarbons known to exist over a large area.

SEC: United States Securities and Exchange Commission.

Shale: A fine-grained, fissile, sedimentary rock formed by consolidation of clay- and silt-sized particles into thin, relatively impermeable layers.

SWD: Saltwater disposal.

throughput: The volume of product passing through a pipeline, plant, terminal or other facility.

Tubulars: A generic term pertaining to any type of crude oilfield pipe, such as drillpipe, drill collars, pup joints, casing, production tubing and pipeline.

Unconventional resource: An umbrella term for crude oil and natural gas that is produced by means that do not meet the criteria for conventional production. What has qualified as “unconventional” at any particular time is a complex function of resource characteristics, the available E&P technologies, the economic environment, and the scale, frequency and duration of production from the resource. Perceptions of these factors inevitably change over time and often differ among users of the term. At present, the term is used in reference to crude oil and natural gas resources whose porosity, permeability, fluid trapping mechanism, or other characteristics differ from conventional sandstone and carbonate reservoirs. Coalbed methane, gas hydrates, shale gas, fractured reservoirs and tight gas sands are considered unconventional resources.

Well stimulation: A treatment performed to restore or enhance the productivity of a well. Stimulation treatments fall into two main groups, hydraulic fracturing treatments and matrix treatments. Fracturing treatments are performed above the fracture pressure of the reservoir formation and create a highly conductive flow path between the reservoir and the wellbore. Matrix treatments are performed below the reservoir fracture pressure and generally are designed to restore the natural permeability of the reservoir following damage to the near-wellbore area. Stimulation in shale gas reservoirs typically takes the form of hydraulic fracturing treatments.

Wellbore: The physical conduit from surface into the hydrocarbon reservoir.

Workover: The process of performing major maintenance or remedial treatments on an crude oil or natural gas well. In many cases, workover implies the removal and replacement of the production tubing string after the well has been killed and a workover rig has been placed on location. Through-tubing workover operations, using coiled tubing, snubbing or slickline equipment, are routinely conducted to complete treatments or well service activities that avoid a full workover where the tubing is removed. This operation saves considerable time and expense.

EXHIBIT 4.1

**DESCRIPTION OF THE REGISTRANT'S SECURITIES
REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES
EXCHANGE ACT OF 1934**

DESCRIPTION OF THE COMMON UNITS

The Units

The common units and the subordinated units are separate classes of limited partner interests in us. Unitholders are entitled to participate in partnership distributions and exercise the rights or privileges available to limited partners under our partnership agreement. For a description of the relative rights and preferences of unitholders in and to partnership distributions, please read this section and "How We Make Distributions To Our Partners." For a description of other rights and privileges of limited partners under our partnership agreement, including voting rights, please read "The Partnership Agreement." All references to "Oasis Midstream Partners," "OMP," "the Partnership," "us," "our," "we" or similar expressions, refer to Oasis Midstream Partners LP, including its consolidated subsidiaries. References to our "general partner," refer to OMP GP LLC. References to "Oasis Petroleum" may refer to Oasis Petroleum Inc. and/or its consolidated subsidiaries, depending on the context.

Our common units are currently listed on The Nasdaq Stock Market LLC ("Nasdaq") under the symbol "OMP."

Transfer Agent and Registrar

Duties

Computershare Trust Company, N.A. serves as the registrar and transfer agent for the common units. We pay all fees charged by the transfer agent for transfers of common units except the following, which must be paid by our common unitholders:

- surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges;
- special charges for services requested by a common unitholder; and
- other similar fees or charges.

There is no charge to our unitholders for disbursements of our cash distributions. We will indemnify the transfer agent, its agents and each of their stockholders, directors, officers and employees against all claims and losses that may arise out of acts performed or omitted for its activities in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

Resignation or Removal

The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor is appointed or has not accepted its appointment within 30 days of the resignation or removal, our general partner may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

Upon the transfer of a common unit in accordance with our partnership agreement, the transferee of the common unit shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission are reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;

- automatically becomes bound by the terms and conditions of our partnership agreement; and
- gives the consents, waivers and approvals contained in our partnership agreement.

Our general partner will cause any transfers to be recorded on our books and records no less frequently than quarterly.

We may, at our discretion, treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and any transfers are subject to the laws governing the transfer of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a substituted limited partner in our partnership for the transferred common units.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the common unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

Number of Common Units and Subordinated Units

As of February 19, 2020, we had 33,811,366 units representing limited partner interests (consisting of 20,061,366 common units and 13,750,000 subordinated units) outstanding. Our common units are traded on Nasdaq under the symbol "OMP." Oasis Petroleum owns all of the Partnership's subordinated units. There is currently no established public trading market for our subordinated units.

DESCRIPTION OF PARTNERSHIP SECURITIES

Our partnership agreement authorizes us to issue an unlimited number of additional partnership interests for the consideration and on the terms and conditions determined by our general partner without the approval of the unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units, subordinated units or other partnership interests. Holders of any additional common units we issue will be entitled to share equally with the then-existing common unitholders in our distributions. In addition, the issuance of additional common units or other partnership interests may dilute the value of the interests of the then-existing common unitholders in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership interests that, as determined by our general partner, may have rights to distributions or special voting rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit the issuance by our subsidiaries of equity interests that may effectively rank senior to the common units.

Our general partner is authorized to approve the issuance of one or more series of partnership securities without further authorization of the limited partners and to fix the number of securities, the designations, rights, privileges, restrictions and conditions of any such series.

Should we offer any such series of partnership securities under our shelf registration statement on Form S-3, filed with the Securities and Exchange Commission (the "SEC") on October 1, 2018, a prospectus supplement will set forth the number of securities, particular designation, relative rights and preferences and the limitations of such series of partnership securities. The particular terms of any such series may include the following:

- the maximum number, if any, of securities to constitute the series and the designation and ranking thereof;

- the distribution rate, if any, on securities of the series, whether such rate is fixed or variable or both, the dates from which distributions will begin to accrue or accumulate, whether distributions will be cumulative and whether such distributions will be paid in cash, securities or otherwise;
- whether the securities of the series will be redeemable and, if so, the price and the terms and conditions on which the securities of the series may be redeemed, including the time during which securities of the series may be redeemed and any accumulated distributions thereof that the holders of the securities of the series will be entitled to receive upon the redemption thereof;
- the liquidation preference, if any, applicable to securities of the series;
- the terms and conditions, if any, on which the securities of the series will be convertible into, or exchangeable for, securities of any other class or classes of partnership securities, including the price or prices or the rate or rates of conversion or exchange and the method, if any, of adjusting the same;
- the voting rights, if any, of the securities of the series;
- a discussion of any additional material federal income tax considerations, if any, regarding the securities; and
- any additional rights, preferences, privileges, limitations and restrictions of the securities.

Partnership securities will be fully paid and non-assessable when issued upon full payment of the purchase price therefor. The prospectus supplement will contain, if applicable, a description of the material U.S. federal income tax consequences relating to the purchase and ownership of the series of partnership securities offered by the prospectus supplement. The transfer agent, registrar and distributions disbursement agent for the partnership securities will be designated in the applicable prospectus supplement.

HOW WE MAKE DISTRIBUTIONS TO OUR PARTNERS

General

Cash Distribution Policy

Our partnership agreement provides that our general partner will make a determination as to whether to make a distribution, but does not require us to pay distributions at any time or in any amount. Instead, the board of directors of our general partner has adopted a cash distribution policy that sets forth our general partner’s intention with respect to the distributions to be made to unitholders. Pursuant to our cash distribution policy, we intend to distribute to the holders of common units and subordinated units on a quarterly basis at least the minimum quarterly distribution of $0.3750 per unit, or $1.50 on an annualized basis, to the extent we have sufficient cash after establishment of cash reserves and payment of fees and expenses, including payments to our general partner and its affiliates.

The board of directors of our general partner may change the foregoing distribution policy at any time and from time to time, and even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our distribution policy and the decision to make any distribution is determined by our general partner. Our partnership agreement does not contain a requirement for us to pay distributions to our unitholders, and there is no guarantee that we will pay the minimum quarterly distribution, or any distribution, on the units in any quarter. However, our partnership agreement does contain provisions intended to motivate our general partner to make steady, increasing and sustainable distributions over time.

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

Operating Surplus and Capital Surplus

General

Any distributions we make are characterized as made from "operating surplus" or "capital surplus." Distributions from operating surplus are made differently than cash distributions that we would make from capital surplus. Operating surplus distributions will be made to our unitholders and, if we make quarterly distributions above the first target distribution level described below, to the holder of our incentive distribution rights. We do not anticipate that we will make any distributions from capital surplus. In such an event, however, any capital surplus distribution would be made pro rata to all unitholders, but the incentive distribution rights would generally not participate in any capital surplus distributions. Any distribution from capital surplus would result in a reduction of the minimum quarterly distribution and target distribution levels and, if we reduce the minimum quarterly distribution to zero and eliminate any unpaid arrearages, thereafter capital surplus would be distributed as if it were operating surplus and the incentive distribution rights would thereafter be entitled to participate in such distributions. Please see "—Distributions from Capital Surplus."

Operating Surplus

We define operating surplus as:

- $40.0 million (as described below); *plus*
- all of our cash receipts after the closing of our initial public offering ("IPO"), excluding cash from interim capital transactions (as defined below) and provided that cash receipts from the termination of any hedge contract prior to its stipulated settlement or termination date will be included in equal quarterly installments over the remaining scheduled life of such hedge contract had it not been terminated; *plus*
- cash distributions paid in respect of equity issued (including incremental distributions on incentive distribution rights), other than equity issued in our IPO, to finance all or a portion of expansion capital expenditures in respect of the period that commences when we enter into a binding obligation for the acquisition, construction, development or expansion and ending on the earlier to occur of the date any acquisition, construction, development or expansion commences commercial service and the date that it is disposed of or abandoned; *plus*
- cash distributions paid in respect of equity issued (including incremental distributions on incentive distribution rights), other than equity issued in our IPO, to pay the construction period interest on debt incurred, or to pay construction period distributions on equity issued, to finance the expansion capital expenditures referred to above, in each case, in respect of the period that commences when we enter into a binding obligation for the acquisition, construction, development or expansion and ending on the earlier to occur of the date any acquisition, construction, development or expansion commences commercial service and the date that it is disposed of or abandoned; *less*
- all of our operating expenditures (as defined below) after our IPO, which includes maintenance capital expenditures after our IPO; *less*
- the amount of cash reserves established by our general partner to provide funds for future operating expenditures; *less*
- all working capital borrowings not repaid within twelve months after having been incurred, or repaid within such twelve-month period with the proceeds of additional working capital borrowings; *less*
- any cash loss realized on disposition of an investment capital expenditure.

Disbursements made, cash received (including working capital borrowings) or cash reserves established, increased or reduced after the end of a period but on or before the date on which cash or cash equivalents will be distributed with respect to such period shall be deemed to have been made, received, established, increased or reduced, for purposes of determining operating surplus, within such period if our general partner so determines. Furthermore, cash received from an interest in an entity for which we account using the equity method will not be included to the extent it exceeds our proportionate share of that entity's operating surplus (calculated as if the definition of operating surplus applied to such entity from the date of our acquisition of such an interest without any basket similar to that described in the first bullet above). Operating surplus does not reflect cash generated by our operations. For example, it includes a basket of $40.0 million that will enable us, if we choose, to distribute as operating surplus cash we receive in the future from non-operating sources such as asset sales, issuances of securities and long-term borrowings that would otherwise be distributed as capital surplus. In addition, the effect of including, as described above, certain cash distributions on equity interests in operating surplus will be to increase operating surplus by the amount of any such cash distributions. As a result, we may also distribute as operating surplus up to the amount of any such cash that we receive from non-operating sources.

The proceeds of working capital borrowings increase operating surplus, and repayments of working capital borrowings are generally operating expenditures, as described below, and thus reduce operating surplus when made. However, if a working capital borrowing is not repaid during the twelve-month period following the borrowing, it will be deducted from operating surplus at the end of such period, thus decreasing operating surplus at such time. When such working capital borrowing is in fact repaid, it will be excluded from operating expenditures because operating surplus will have been previously reduced by the deduction.

We define operating expenditures in our partnership agreement, and it generally means all of our cash expenditures, including, but not limited to, taxes, reimbursement of expenses to our general partner or its affiliates, payments made under interest rate hedge agreements or commodity hedge agreements (provided that (1) with respect to amounts paid in connection with the initial purchase of an interest rate hedge contract or a commodity hedge contract, such amounts will be amortized over the life of the applicable interest rate hedge contract or commodity hedge contract and (2) payments made in connection with the termination of any interest rate hedge contract or commodity hedge contract prior to the expiration of its stipulated settlement or termination date will be included in operating expenditures in equal quarterly installments over the remaining scheduled life of such interest rate hedge contract or commodity hedge contract), officer compensation, repayment of working capital borrowings, interest on indebtedness and capital expenditures (as discussed in further detail below). However, operating expenditures do not include:

- repayment of working capital borrowings deducted from operating surplus pursuant to the penultimate bullet point of the definition of operating surplus above when such repayment actually occurs;
- payments (including prepayments and prepayment penalties and the purchase price of indebtedness that is repurchased and cancelled) of principal of and premium on indebtedness, other than working capital borrowings;
- expansion capital expenditures;
- investment capital expenditures;
- payment of transaction expenses relating to interim capital transactions;
- distributions to our partners (including distributions in respect of our incentive distribution rights); or
- repurchases of equity interests except to fund obligations under employee benefit plans.

Capital Surplus

Capital surplus is defined in our partnership agreement as any cash distributed in excess of our operating surplus. Accordingly, capital surplus would generally be generated only by the following (which we refer to as “interim capital transactions”):

- borrowings other than working capital borrowings;
- sales of our equity interests; and
- sales or other dispositions of assets for cash, other than inventory, accounts receivable and other assets sold in the ordinary course of business or as part of normal retirement or replacement of assets.

Characterization of Cash Distributions

Our partnership agreement provides that we treat all cash distributed as coming from operating surplus until the sum of all cash distributed since the closing of our IPO equals the operating surplus from the closing of our IPO. Our partnership agreement provides that we treat any amount distributed in excess of operating surplus, regardless of its source, as distributions of capital surplus. We do not anticipate that we will make any distributions from capital surplus.

Capital Expenditures

Maintenance capital expenditures reduce operating surplus, but expansion capital expenditures and investment capital expenditures do not. Maintenance capital expenditures are cash expenditures (including expenditures for the construction or development of new capital assets or the replacement, improvement or expansion of existing capital assets) made to maintain, over the long term, our system operating capacity, operating income or revenue. Examples of maintenance capital expenditures are expenditures to repair, refurbish and replace pipelines, to maintain equipment reliability, integrity and safety and to comply with environmental laws and regulations. In addition, we designate a portion of our capital expenditures to connect new wells to maintain gathering throughput as maintenance capital expenditures to the extent such capital expenditures are necessary to maintain, over the long term, system operating capacity, operating income or revenue. Cash expenditures made solely for investment purposes will not be considered maintenance capital expenditures.

Expansion capital expenditures are cash expenditures to acquire additional interests in our midstream assets and to construct new midstream infrastructure and those expenditures incurred in order to extend the useful lives of our assets, reduce costs, increase revenues or increase system throughput or capacity from current levels, including well connections that increase existing system operating capacity, operating income or revenue. Examples of expansion capital expenditures include the acquisition of additional interests in our development companies and the construction, development or acquisition of additional midstream assets, in each case, to the extent such expenditures are expected to increase, over the long term, system operating capacity, operating income or revenue. If we make acquisitions that increase system operating capacity, operating income or revenue, the associated capital expenditures will also include interest (and related fees) on debt incurred and distributions on equity issued (including incremental distributions on incentive distribution rights) to finance all or any portion of such acquisition, development or expansion in respect of the period that commences when we enter into a binding obligation for the acquisition, construction, development or expansion and ending on the earlier to occur of the date any acquisition, construction, development or expansion commences commercial service and the date that it is disposed of or abandoned. Expenditures made solely for investment purposes are not considered expansion capital expenditures.

Investment capital expenditures are those capital expenditures, including transaction expenses, which are neither maintenance capital expenditures nor expansion capital expenditures. Investment capital expenditures largely will consist of capital expenditures made for investment purposes. Examples of investment capital expenditures include traditional capital expenditures for investment purposes, such as purchases of securities, as well as other capital expenditures that might be made in lieu of such traditional investment capital expenditures, such as the acquisition of an asset for investment purposes or development of assets that are in excess of the maintenance of existing system operating capacity or operating income, but which are not expected to expand, for more than the short term, system operating capacity or operating income.

As described above, neither investment capital expenditures nor expansion capital expenditures are operating expenditures, and thus do not reduce operating surplus. Because expansion capital expenditures include interest payments (and related fees) on debt incurred to finance all or a portion of an acquisition, development or expansion in respect of a period that begins when we enter into a binding obligation for an acquisition, construction, development or expansion and ending on the earlier to occur of the date on which such acquisition, construction, development or expansion commences commercial service and the date that it is abandoned or disposed of, such interest payments also do not reduce operating surplus. Losses on disposition of an investment capital expenditure reduce operating surplus when realized and cash receipts from an investment capital expenditure are treated as a cash receipt for purposes of calculating operating surplus only to the extent the cash receipt is a return on principal.

Cash expenditures that are made in part for maintenance capital purposes, investment capital purposes or expansion capital purposes are allocated as maintenance capital expenditures, investment capital expenditures or expansion capital expenditures by our general partner.

Subordination Period

General

Our partnership agreement provides that, during the subordination period (as described below), the common unitholders will have the right to receive distributions from operating surplus each quarter in an amount equal to $0.3750 per common unit, which amount is defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on our common units from prior quarters, before any distributions from operating surplus may be made on our subordinated units. These units are deemed “subordinated” because for a period of time, referred to as the subordination period, our subordinated units are not entitled to receive any distributions from operating surplus for any quarter until our common units have received the minimum quarterly distribution from operating surplus for such quarter plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Furthermore, no arrearages are paid on our subordinated units. The practical effect of our subordinated units is to increase the likelihood that during the subordination period there will be sufficient cash from operating surplus to pay the minimum quarterly distribution on our common units.

Determination of Subordination Period

Oasis Petroleum currently owns all of our subordinated units. The subordination period began on the closing date of our IPO and, except as described below, will expire on the first business day after the distribution to unitholders in respect of any quarter, beginning with the quarter ending December 31, 2020, if each of the following has occurred:

- for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date, aggregate distributions from operating surplus equaled or exceeded the sum of the minimum quarterly distribution multiplied by the total number of common units and subordinated units outstanding in each quarter in each period;

- for the same three consecutive, non-overlapping four-quarter periods, the “adjusted operating surplus” (as described below) equaled or exceeded the sum of the minimum quarterly distribution multiplied by the total number of common units and subordinated units outstanding during each quarter on a fully diluted weighted average basis; and

- there are no arrearages in payment of the minimum quarterly distribution on our common units.

For the period after the closing of our IPO through September 30, 2017, our partnership agreement prorated the minimum quarterly distribution based on the actual length of the period, and uses such prorated distribution for all purposes, including in determining whether the test described above has been satisfied.

Early Termination of Subordination Period

Notwithstanding the foregoing, the subordination period will automatically terminate, and all of the subordinated units will convert into common units on a one-for-one basis, on the first business day after the distribution to unitholders in respect of any quarter, beginning with the quarter ending December 31, 2018, if each of the following has occurred:

- for one four-quarter period immediately preceding that date, aggregate distributions from operating surplus exceeded 150.0% of the minimum quarterly distribution multiplied by the total number of common units and subordinated units outstanding in each quarter in the period;

- for the same four-quarter period, the "adjusted operating surplus" (as described below) equaled or exceeded 150.0% of the sum of the minimum quarterly distribution multiplied by the total number of common units and subordinated units outstanding during each quarter on a fully diluted weighted average basis, plus the related distribution on the incentive distribution rights; and

- there are no arrearages in payment of the minimum quarterly distributions on our common units.

Expiration of the Subordination Period

When the subordination period ends, each outstanding subordinated unit will convert into one common unit, which will then participate pro-rata with the other common units in distributions.

Adjusted Operating Surplus

Adjusted operating surplus is intended to generally reflect the cash generated from operations during a particular period and therefore excludes net increases in working capital borrowings and net drawdowns of reserves of cash generated in prior periods if not utilized to pay expenses during that period. Adjusted operating surplus for any period consists of:

- operating surplus generated with respect to that period (excluding any amounts attributable to the items described in the first bullet point under "—Operating Surplus and Capital Surplus—Operating Surplus" above); less

- any net increase during that period in working capital borrowings; less

- any net decrease during that period in cash reserves for operating expenditures not relating to an operating expenditure made during that period; plus

- any net decrease during that period in working capital borrowings; plus

- any net increase during that period in cash reserves for operating expenditures required by any debt instrument for the repayment of principal, interest or premium; plus

- any net decrease made in subsequent periods in cash reserves for operating expenditures initially established during such period to the extent such decrease results in a reduction of adjusted operating surplus in subsequent periods pursuant to the third bullet point above.

Any disbursements received, cash received (including working capital borrowings) or cash reserves established, increased or reduced after the end of a period that the general partner determines to include in operating surplus for such period shall also be deemed to have been made, received or established, increased or reduced in such period for purposes of determining adjusted operating surplus for such period.

Distributions From Operating Surplus During the Subordination Period

If we make distributions of cash from operating surplus for any quarter ending before the end of the subordination period, our partnership agreement requires that we make the distribution in the following manner:

- *first*, to the common unitholders, pro rata, until we distribute for each common unit an amount equal to the minimum quarterly distribution for that quarter and any arrearages in payment of the minimum quarterly distribution on our common units for any prior quarters;

- *second*, to the subordinated unitholders, pro rata, until we distribute for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and

- *thereafter*, in the manner described in "—Incentive Distribution Rights" below.

Distributions From Operating Surplus After the Subordination Period

If we make distributions of cash from operating surplus for any quarter ending after the subordination period, our partnership agreement requires that we make the distribution in the following manner:

- *first*, to all common unitholders, pro rata, until we distribute for each common unit an amount equal to the minimum quarterly distribution for that quarter; and
- *thereafter*, in the manner described in "—Incentive Distribution Rights" below.

General Partner Interest

Our general partner owns a non-economic general partner interest in us, which does not entitle it to receive cash distributions. However, our general partner may in the future own common units or other equity interests in us and will be entitled to receive distributions on any such interests.

Incentive Distribution Rights

Incentive distribution rights represent the right to receive increasing percentages (15%, 25% and 50%) of quarterly distributions from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. Our general partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest.

If for any quarter:

- we have distributed cash from operating surplus to the common unitholders and subordinated unitholders in an amount equal to the minimum quarterly distribution; and
- we have distributed cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution; then we will make additional distributions from operating surplus for that quarter among the unitholders and the holders of the incentive distribution rights in the following manner:

- *first*, to all unitholders, pro rata, until each unitholder receives a total of $0.43125 per unit for that quarter, or the first target distribution;
- *second*, 85% to all common unitholders and subordinated unitholders, pro rata, and 15% to the holders of our incentive distribution rights, until each unitholder receives a total of $0.46875 per unit for that quarter, or the second target distribution;
- *third*, 75% to all common unitholders and subordinated unitholders, pro rata, and 25% to the holders of our incentive distribution rights, until each unitholder receives a total of $0.56250 per unit for that quarter, or the third target distribution; and
- *thereafter*, 50% to all common unitholders and subordinated unitholders, pro rata, and 50% to the holders of our incentive distribution rights.

Percentage Allocations of Distributions From Operating Surplus

The following table illustrates the percentage allocations of distributions from operating surplus between the unitholders and the holders of our incentive distribution rights based on the specified target distribution levels. The amounts set forth under the column heading "Marginal Percentage Interest in Distributions" are the percentage interests of the holders of our incentive distribution rights and the unitholders in any distributions from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Per Unit." The percentage interests shown for our unitholders and the holders of our incentive distribution rights for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below assume there are no arrearages on common units.

	Total Quarterly Distribution Per Unit	Marginal Percentage Interest in Distributions	
		Unitholders	IDR Holders
Minimum Quarterly Distribution	$0.37500	100 %	— %
First Target Distribution	above $0.37500 up to $0.43125	100 %	— %
Second Target Distribution	above $0.43125 up to $0.46875	85 %	15 %
Third Target Distribution	above $0.46875 up to $0.56250	75 %	25 %
Thereafter	above $0.56250	50 %	50 %

Right to Reset Incentive Distribution Levels

The holder of our incentive distribution rights has the right under our partnership agreement to elect to relinquish the right to receive incentive distribution payments based on the initial target distribution levels and to reset, at higher levels, the target distribution levels upon which the incentive distribution payments would be set. If our general partner transfers all or a portion of the incentive distribution rights in the future, then the holder or holders of a majority of our incentive distribution rights will be entitled to exercise this right. The following discussion assumes that our general partner holds all of the incentive distribution rights at the time that a reset election is made.

The right to reset the target distribution levels upon which the incentive distributions are based may be exercised, without approval of our unitholders or the conflicts committee of our general partner, at any time when there are no subordinated units outstanding and we have made cash distributions to the holders of the incentive distribution rights at the highest level of incentive distribution for the prior four consecutive fiscal quarters. The reset target distribution levels will be higher than the target distribution levels prior to the reset such that there will be no incentive distributions paid under the reset target distribution levels until cash distributions per unit following the reset event increase as described below. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would otherwise not be sufficiently accretive to cash distributions per common unit, taking into account the existing levels of incentive distribution payments being made.

In connection with the resetting of the target distribution levels and the corresponding relinquishment by our general partner of incentive distribution payments based on the target cash distributions prior to the reset, our general partner will be entitled to receive a number of newly issued common units based on the formula described below that takes into account the “cash parity” value of the cash distributions related to the incentive distribution rights for the quarter prior to the reset event as compared to the cash distribution per common unit in such quarter.

The number of common units to be issued in connection with a resetting of the minimum quarterly distribution amount and the target distribution levels would equal the quotient determined by dividing (x) the amount of cash distributions received in respect of the incentive distribution rights for the fiscal quarter ended immediately prior to the date of such reset election by (y) the amount of cash distributed per common unit with respect to such quarter.

Following a reset election, a baseline minimum quarterly distribution amount will be calculated as an amount equal to the cash distribution amount per unit for the fiscal quarter immediately preceding the reset election (which amount we refer to as the “reset minimum quarterly distribution”) and the target distribution levels will be reset to be correspondingly higher such that we would make distributions from operating surplus for each quarter thereafter as follows:

- *first*, to all common unitholders, pro rata, until each unitholder receives an amount per unit equal to 115% of the reset minimum quarterly distribution for that quarter;

- *second*, 85% to all common unitholders, pro rata, and 15% to the holders of our incentive distribution rights, until each unitholder receives an amount per unit equal to 125% of the reset minimum quarterly distribution for the quarter;

- *third*, 75% to all common unitholders, pro rata, and 25% to the holders of our incentive distribution rights, until each unitholder receives an amount per unit equal to 150% of the reset minimum quarterly distribution for the quarter; and

- *thereafter*, 50% to all common unitholders, pro rata, and 50% to the holders of our incentive distribution rights.

Because a reset election can only occur after the subordination period expires, the reset minimum quarterly distribution will have no significance except as a baseline for the target distribution levels.

The holders of our incentive distribution rights are entitled to cause the target distribution levels to be reset on more than one occasion. There are no restrictions on the ability of holders of our incentive distribution rights to exercise the reset right multiple times, but the requirements for exercise must be met each time. Because one of the requirements is that we make cash distributions in excess of the then-applicable third target distribution for the prior four consecutive fiscal quarters, a minimum of four quarters must elapse between each reset.

Distributions From Capital Surplus

How Distributions From Capital Surplus Will Be Made

Our partnership agreement requires that we make distributions from capital surplus, if any, in the following manner:

- *first*, to all common unitholders and subordinated unitholders, pro rata, until the minimum quarterly distribution is reduced to zero, as described below;

- *second*, to the common unitholders, pro rata, until we distribute for each common unit an amount from capital surplus equal to any unpaid arrearages in payment of the minimum quarterly distribution on the common units; and

- *thereafter*, we will make all distributions from capital surplus as if they were from operating surplus.

Effect of a Distribution From Capital Surplus

Our partnership agreement treats a distribution from capital surplus as the repayment of the initial unit price from our IPO, which is a return of capital. Each time a distribution from capital surplus is made, the minimum quarterly distribution and the target distribution levels will be reduced in the same proportion as the distribution from capital surplus to the fair market value of our common units prior to the announcement of the distribution. Because distributions from capital surplus will reduce the minimum quarterly distribution and target distribution levels after any of these distributions are made, it may be easier for our general partner to receive incentive distributions and for the subordinated units to convert into common units. However, any distribution from capital surplus before the minimum quarterly distribution is reduced to zero cannot be applied to the payment of the minimum quarterly distribution or any arrearages.

Once we reduce the minimum quarterly distribution and target distribution levels to zero and eliminate any arrearages, all future distributions will be made such that 50% is paid to all unitholders, pro rata, and 50% is paid to the holder or holders of incentive distribution rights, pro rata.

Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels

In addition to adjusting the minimum quarterly distribution and target distribution levels to reflect a distribution from capital surplus, if we combine our common units into fewer common units or subdivide our common units into a greater number of common units, our partnership agreement specifies that the following items will be proportionately adjusted:

- the minimum quarterly distribution;
- the target distribution levels;
- the initial unit price, as described below under "—Distributions of Cash Upon Liquidation";
- the per unit amount of any outstanding arrearages in payment of the minimum quarterly distribution on our common units; and
- the number of subordinated units.

For example, if a two-for-one split of our common units should occur, the minimum quarterly distribution, the target distribution levels and the initial unit price would each be reduced to 50% of its initial level. If we combine our common units into a lesser number of units or subdivide our common units into a greater number of units, we will combine or subdivide our subordinated units using the same ratio applied to our common units. We will not make any adjustment by reason of the issuance of additional units for cash or property.

In addition, if, as a result of a change in law or interpretation thereof, we or any of our subsidiaries is treated as an association taxable as a corporation or is otherwise subject to additional taxation as an entity for U.S. federal, state, local or non-U.S. income or withholding tax purposes, our general partner may, in its sole discretion, reduce the minimum quarterly distribution and the target distribution levels for each quarter by multiplying each distribution level by a fraction, the numerator of which is cash for that quarter (after deducting our general partner's estimate of our additional aggregate liability for the quarter for such income and withholding taxes payable by reason of such change in law or interpretation) and the denominator of which is the sum of (1) cash for that quarter, plus (2) our general partner's estimate of our additional aggregate liability for the quarter for such income and withholding taxes payable by reason of such change in law or interpretation thereof.

Distributions of Cash Upon Liquidation

General

If we dissolve in accordance with the partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders and the holders of the incentive distribution rights, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

The allocations of gain and loss upon liquidation are intended, to the extent possible, to entitle the holders of units to a repayment of the initial value contributed by unitholders for their units, which we refer to as the "initial unit price" for each unit. The allocations of gain and loss upon liquidation are also intended, to the extent possible, to entitle the holders of common units to a preference over the holders of subordinated units upon our liquidation, to the extent required to permit common unitholders to receive their initial unit price plus the minimum quarterly distribution for the quarter during which liquidation occurs plus any unpaid arrearages in payment of the minimum quarterly distribution on our common units. However, there may not be sufficient gain upon our liquidation to enable the common unitholders to fully recover all of these amounts, even though there may be cash available for distribution to the holders of subordinated units. Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights.

Manner of Adjustments for Gain

The manner of the adjustment for gain is set forth in the partnership agreement. If our liquidation occurs before the end of the subordination period, we will generally allocate any gain to the partners in the following manner:

- *first*, to our general partner to the extent of certain prior losses specially allocated to our general partner;
- *second*, to the common unitholders, pro rata, until the capital account for each common unit is equal to the sum of: (1) the initial unit price; (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs; and (3) any unpaid arrearages in payment of the minimum quarterly distribution;
- *third*, to the subordinated unitholders, pro rata, until the capital account for each subordinated unit is equal to the sum of: (1) the initial unit price; and (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs;
- *fourth*, to all unitholders, pro rata, until we allocate under this bullet an amount per unit equal to: (1) the sum of the excess of the first target distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions from operating surplus in excess of the minimum quarterly distribution per unit that we distributed to the unitholders, pro rata, for each quarter of our existence;
- *fifth*, 85% to all unitholders, pro rata, and 15% to the holders of our incentive distribution rights, until we allocate under this bullet an amount per unit equal to: (1) the sum of the excess of the second target distribution per unit over the first target distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions from operating surplus in excess of the first target distribution per unit that we distributed 85% to the unitholders, pro rata, and 15% to the holders of our incentive distribution rights for each quarter of our existence;
- *sixth*, 75% to all unitholders, pro rata, and 25% to the holders of our incentive distribution rights, until we allocate under this bullet an amount per unit equal to: (1) the sum of the excess of the third target distribution per unit over the second target distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions from operating surplus in excess of the second target distribution per unit that we distributed 75% to the unitholders, pro rata, and 25% to the holders of our incentive distribution rights for each quarter of our existence; and
- *thereafter*, 50% to all unitholders, pro rata, and 50% to holders of our incentive distribution rights.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that clause (3) of the second bullet point above and all of the third bullet point above will no longer be applicable.

We may make special allocations of gain among the partners in a manner to create economic uniformity among the common units into which the subordinated units convert and the common units held by public unitholders.

Manner of Adjustments for Losses

If our liquidation occurs before the end of the subordination period, we will generally allocate any loss to our general partner and the unitholders in the following manner:

- *first*, to the holders of subordinated units in proportion to the positive balances in their capital accounts until the capital accounts of the subordinated unitholders have been reduced to zero;

- *second*, to the holders of common units in proportion to the positive balances in their capital accounts, until the capital accounts of the common unitholders have been reduced to zero; and

- *thereafter*, 100% to our general partner.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that all of the first bullet point above will no longer be applicable.

We may make special allocations of loss among the partners in a manner to create economic uniformity among the common units into which the subordinated units convert and the common units held by public unitholders.

Adjustments to Capital Accounts

Our partnership agreement requires that we make adjustments to capital accounts upon the issuance of additional units. In this regard, our partnership agreement specifies that we allocate any unrealized and, for federal income tax purposes, unrecognized gain resulting from the adjustments to the unitholders and the holders of our incentive distribution rights in the same manner as we allocate gain upon liquidation. In the event that we make positive adjustments to the capital accounts upon the issuance of additional units, our partnership agreement requires that we generally allocate any later negative adjustments to the capital accounts resulting from the issuance of additional units or upon our liquidation in a manner that results, to the extent possible, in the partners' capital account balances equaling the amount that they would have been if no earlier positive adjustments to the capital accounts had been made. In contrast to the allocations of gain, and except as provided above, we generally will allocate any unrealized and unrecognized loss resulting from the adjustments to capital accounts upon the issuance of additional units to the unitholders and the holders of our incentive distribution rights based on their respective percentage ownership of us. In this manner, prior to the end of the subordination period, we generally will allocate any such loss equally with respect to our common units and subordinated units. If we make negative adjustments to the capital accounts as a result of such loss, future positive adjustments resulting from the issuance of additional units will be allocated in a manner designed to reverse the prior negative adjustments, and special allocations will be made upon liquidation in a manner that results, to the extent possible, in our unitholders' capital account balances equaling the amounts they would have been if no earlier adjustments for loss had been made.

THE PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement.

Cash Distributions

Our partnership agreement does not require us to pay distributions at any time or in any amount. Instead, the board of directors of our general partner has adopted a cash distribution policy that sets forth our general partner's intention with respect to the distributions to be made to unitholders. The board of directors of our general partner may change our distribution policy and the amount of distributions to be paid under our distribution policy at any time without unitholder approval and for any reason.

Our partnership agreement specifies the manner in which we will make cash distributions to holders of our common units and other partnership securities as well as to our general partner in respect of its incentive distribution rights. For a description of these cash distribution provisions, please read "How We Make Distributions To Our Partners."

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described below under "—Limited Liability."

Voting Rights

The following is a summary of the unitholder vote required for approval of the matters specified below. Matters that require the approval of a "unit majority" require:

- during the subordination period, the approval of a majority of the common units, excluding those common units whose vote is controlled by our general partner or its affiliates, and a majority of the subordinated units, voting as separate classes; and
- after the subordination period, the approval of a majority of the common units.

In voting their common units and subordinated units, our general partner and its affiliates will have no duty or obligation whatsoever to us or the limited partners, including any duty to act in the best interests of us or the limited partners.

The incentive distribution rights may be entitled to vote in certain circumstances.

Issuance of additional units	No approval right.
Amendment of the partnership agreement	Certain amendments may be made by our general partner without the approval of the unitholders. Other amendments generally require the approval of a unit majority. Please read "—Amendment of the Partnership Agreement."
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority in certain circumstances. Please read "—Merger, Consolidation, Conversion, Sale or Other Disposition of Assets."
Dissolution of our partnership	Unit majority. Please read "—Dissolution."
Continuation of our business upon dissolution	Unit majority. Please read "—Dissolution."
Withdrawal of our general partner	No approval right. Please read "—Withdrawal or Removal of Our General Partner."
Removal of our general partner	Not less than 66 2/3% of the outstanding units, voting as a single class, including units held by our general partner and its affiliates, for cause. In addition, any vote to remove our general partner during the subordination period must provide for the election of a successor general partner by the holders of a majority of the common units and a majority of the subordinated units, voting as separate classes. Please read "—Withdrawal or Removal of Our General Partner."
Transfer of our general partner interest	No approval right. Please read "—Transfer of General Partner Interest."
Transfer of incentive distribution rights	No approval right. Please read "—Transfer of Subordinated Units and Incentive Distribution Rights."
Transfer of ownership interests in our general partner	No approval right. Please read "—Transfer of Ownership Interests in the General Partner."

If any person or group other than our general partner and its affiliates acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to Oasis Petroleum or to any person or group that acquires the units from our general partner or its affiliates and any transferees of that person or group approved by our general partner or to any person or group who acquires the units with the specific prior approval of our general partner.

Applicable Law; Forum, Venue and Jurisdiction

Our partnership agreement is governed by Delaware law. Our partnership agreement requires that any claims, suits, actions or proceedings:

- arising out of or relating in any way to the partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of the partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us);
- brought in a derivative manner on our behalf;
- asserting a claim of breach of a duty owed by any director, officer or other employee of us or our general partner, or owed by our general partner, to us or the limited partners;
- asserting a claim arising pursuant to any provision of the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act"); or
- asserting a claim governed by the internal affairs doctrine

shall be exclusively brought in the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction thereof, any other court located in the State of Delaware with subject matter jurisdiction), regardless of whether such claims, suits, actions or proceedings sound in contract, tort, fraud or otherwise, are based on common law, statutory, equitable, legal or other grounds, or are derivative or direct claims. By purchasing a common unit, a limited partner is irrevocably consenting to these limitations and provisions regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other court) in connection with any such claims, suits, actions or proceedings. Under our partnership agreement, if the Court of Chancery of the State of Delaware does not have jurisdiction over any matter, then the applicable claim, suit, action or proceeding is required to be brought in any other court in the State of Delaware having jurisdiction. The exclusive forum provision would not apply to suits brought to enforce any liability or duty created by the Securities Act or the Exchange Act or any other claim for which the federal courts have exclusive jurisdiction. To the extent that any such claims may be based upon federal law claims, Section 27 of the Exchange Act creates exclusive federal jurisdiction over all suits brought to enforce any duty or liability created by the Exchange Act or the rules and regulations thereunder. Furthermore, Section 22 of the Securities Act creates concurrent jurisdiction for federal and state courts over all suits brought to enforce any duty or liability created by the Securities Act or the rules and regulations thereunder.

Reimbursement of Partnership Litigation Costs

Our partnership agreement provides that if limited partners or any persons holding a beneficial interest in us file a claim, suit, action or proceeding against us of a type identified in the bullet points under the above heading "—Applicable Law; Forum, Venue and Jurisdiction" and do not obtain a judgment on the merits that substantially achieves, in substance and amount, the full remedy sought in any such claim, suit, action or proceeding, then such partners or persons will be jointly and severally obligated to reimburse us and our affiliates, including our general partner, the owners of our general partner and any officer or director of our general partner, for all fees, costs and expenses of every kind and description, including but not limited to all reasonable attorneys' fees and other litigation expenses, that the parties may incur in connection with such claim, suit, action or proceeding. Our partnership agreement does not define what constitutes a judgment that "substantially achieves, in substance and amount, the full remedy sought," though we intend to apply a broad interpretation to such provision in order to apply the fee-shifting provision broadly. However, there is no precise established definition of the phrase under applicable law. As a result, whether a specific judgment satisfies the foregoing criteria will be subject to judicial interpretation. By purchasing a common unit, a limited partner is irrevocably consenting to these reimbursement obligations as set forth in our partnership agreement.

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that he otherwise acts in conformity with the provisions of the partnership agreement, his liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital he is obligated to contribute to us for his common units plus his share of any undistributed profits and assets. However, if it were determined that the right, or exercise of the right, by the limited partners as a group:

- to remove or replace our general partner;
- to approve some amendments to our partnership agreement; or
- to take other action under our partnership agreement;

constituted “participation in the control” of our business for the purposes of the Delaware Act, then the limited partners could be held personally liable for our obligations under the laws of Delaware, to the same extent as our general partner. This liability would extend to persons who transact business with us under the reasonable belief that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of a claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership, except that the fair value of property that is subject to a liability for which the recourse of creditors is limited is included in the assets of the limited partnership only to the extent that the fair value of that property exceeds that liability. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years.

Our subsidiaries conduct business in several states and we may have subsidiaries that conduct business in other states or countries in the future. Maintenance of our limited liability as owner of our operating subsidiaries may require compliance with legal requirements in the jurisdictions in which the operating subsidiaries conduct business, including qualifying our subsidiaries to do business there.

Limitations on the liability of members or limited partners for the obligations of a limited liability company or limited partnership have not been clearly established in many jurisdictions. If, by virtue of our ownership interest in our subsidiaries or otherwise, it were determined that we were conducting business in any jurisdiction without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by the limited partners as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under our partnership agreement constituted “participation in the control” of our business for purposes of the statutes of any relevant jurisdiction, then the limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner under the circumstances. We will operate in a manner that our general partner considers reasonable and necessary or appropriate to preserve the limited liability of the limited partners.

Issuance of Additional Interests

Our partnership agreement authorizes us to issue an unlimited number of additional partnership interests for the consideration and on the terms and conditions determined by our general partner without the approval of the unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units, subordinated units or other partnership interests. Holders of any additional common units we issue will be entitled to share equally with the then-existing common unitholders in our distributions. In addition, the issuance of additional common units or other partnership interests may dilute the value of the interests of the then-existing common unitholders in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership interests that, as determined by our general partner, may have rights to distributions or special voting rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit our subsidiaries from issuing equity interests, which may effectively rank senior to the common units.

Our general partner has the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units, subordinated units or other partnership interests whenever, and on the same terms that, we issue partnership interests to persons other than our general partner and its affiliates, to the extent necessary to maintain the percentage interest of our general partner and its affiliates, including such interest represented by common units and subordinated units, that existed immediately prior to each issuance. The common unitholders do not have preemptive rights under our partnership agreement to acquire additional common units or other partnership interests.

Amendment of the Partnership Agreement

General

Amendments to our partnership agreement may be proposed only by our general partner. However, our general partner will have no duty or obligation to propose any amendment and may decline to do so free of any duty or obligation whatsoever to us or the limited partners, including any duty to act in the best interests of us or the limited partners. In order to adopt a proposed amendment, other than the amendments discussed below, our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or to call a meeting of the limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority.

Prohibited Amendments

No amendment may be made that would:

- enlarge the obligations of any limited partner without his consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or

- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld in its sole discretion.

The provision of our partnership agreement preventing the amendments having the effects described in the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units, voting as a single class (including units owned by our general partner and its affiliates). As of February 19, 2020, affiliates of our general partner own approximately 68% of our outstanding limited partner units, including all of our subordinated units.

No Unitholder Approval

Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner to reflect:

- a change in our name, the location of our principal place of business, our registered agent or our registered office;

- the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;

- a change that our general partner determines to be necessary or appropriate to qualify or continue our qualification as a limited partnership or other entity in which the limited partners have limited liability under the laws of any state or to ensure that neither we nor any of our subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes;

- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or its directors, officers, agents or trustees from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisers Act of 1940 or "plan asset" regulations adopted under the Employee Retirement Income Security Act of 1974, or ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed;

- an amendment that our general partner determines to be necessary or appropriate in connection with the creation, authorization or issuance of additional partnership interests, derivative instruments relating to the partnership interests or the right to acquire partnership interests;

- any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;

- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our partnership agreement;

- any amendment that our general partner determines to be necessary or appropriate for the formation by us of, or our investment in, any corporation, partnership or other entity, as otherwise permitted by our partnership agreement;

- a change in our fiscal year or taxable year and related changes;

- conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance; or

- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our general partner may make amendments to our partnership agreement, without the approval of any limited partner, if our general partner determines that those amendments:

- do not adversely affect the limited partners, considered as a whole, or any particular class of partnership interests as compared to other classes of partnership interests in any material respect;

- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;

- are necessary or appropriate to facilitate the trading of limited partner interests or to comply with any rule, regulation, guideline or requirement of any securities exchange on which the limited partner interests are or will be listed for trading;

- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our partnership agreement; or

- are required to effect the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Unitholder Approval

Any amendment that our general partner determines adversely affects in any material respect one or more particular classes of limited partners, and is not permitted to be adopted by our general partner without limited partner approval, will require the approval of at least a majority of the class or classes so affected, but no vote will be required by any class or classes of limited partners that our general partner determines are not adversely affected in any material respect. Any such amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected. Any such amendment that would reduce the voting percentage required to take any action other than to remove the general partner or call a meeting of unitholders is required to be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the voting requirement sought to be reduced. Any such amendment that would increase the percentage of units required to remove the general partner or call a meeting of unitholders must be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the percentage sought to be increased. For amendments of the type not requiring unitholder approval, our general partner will not be required to obtain an opinion of counsel that an amendment will neither result in a loss of limited liability to the limited partners nor result in our being treated as a taxable entity for federal income tax purposes in connection with any of the amendments. No other amendments to our partnership agreement will become effective without the approval of holders of at least 90% of the outstanding units, voting as a single class, unless we first obtain an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any of our limited partners.

Merger, Consolidation, Conversion, Sale or Other Disposition of Assets

A merger, consolidation or conversion of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger, consolidation or conversion and may decline to do so free of any duty or obligation whatsoever to us or the limited partners, including any duty to act in the best interest of us or the limited partners.

In addition, our partnership agreement generally prohibits our general partner, without the prior approval of the holders of a unit majority, from causing us to sell, exchange or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without such approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without such approval. Finally, our general partner may consummate any merger without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the transaction would not result in a material amendment to the partnership agreement (other than an amendment that the general partner could adopt without the consent of other partners), each of our units will be an identical unit of our partnership following the transaction and the partnership interests to be issued do not exceed 20% of our outstanding partnership interests (other than incentive distribution rights) immediately prior to the transaction.

If the conditions specified in our partnership agreement are satisfied, our general partner may convert us or any of our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity, if the sole purpose of that conversion, merger or conveyance is to effect a mere change in our legal form into another limited liability entity, our general partner has received an opinion of counsel regarding limited liability and tax matters and the governing instruments of the new entity provide the limited partners and our general partner with the same rights and obligations as contained in our partnership agreement. Our unitholders are not entitled to dissenters' rights of appraisal under our partnership agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of substantially all of our assets or any other similar transaction or event.

Dissolution

We will continue as a limited partnership until dissolved under our partnership agreement. We will dissolve upon:

- the election of our general partner to dissolve us, if approved by the holders of units representing a unit majority;

- there being no limited partners, unless we are continued without dissolution in accordance with the Delaware Act;

- the entry of a decree of judicial dissolution of our partnership; or

- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than by reason of a transfer of its general partner interest in accordance with our partnership agreement or its withdrawal or removal following the approval and admission of a successor.

Upon a dissolution under the last clause above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of units representing a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability under Delaware law of any limited partner; and

- neither our partnership nor any of our subsidiaries would be treated as an association taxable as a corporation or otherwise be taxable as an entity for federal income tax purposes upon the exercise of that right to continue (to the extent not already so treated or taxed).

Liquidation and Distribution of Proceeds

Upon our dissolution, unless our business is continued, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate, liquidate our assets and apply the proceeds of the liquidation as described in “How We Make Distributions To Our Partners—Distributions of Cash Upon Liquidation.” The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to our partners.

Withdrawal or Removal of Our General Partner

Our general partner may withdraw as general partner in compliance with our partnership agreement after giving 90 days’ written notice to our unitholders.

Upon withdrawal of our general partner under any circumstances, other than as a result of a transfer by our general partner of all or a part of its general partner interest in us, the holders of a unit majority may select a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within a specified period after that withdrawal the holders of a unit majority agree in writing to continue our business and to appoint a successor general partner. Please read “—Dissolution.”

Our general partner may not be removed unless that removal is for cause and is approved by the vote of the holders of not less than 66 2/3% of the outstanding units, voting together as a single class, including units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of the outstanding common units, voting as a class, and the outstanding subordinated units, voting as a class. The ownership of more than 33 1/3% of the outstanding units by our general partner and its affiliates gives them the ability to prevent our general partner’s removal. As of February 19, 2020, affiliates of our general partner own approximately 68% of our outstanding limited partner units, including all of our subordinated units.

In the event of the removal of our general partner or withdrawal of our general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the general partner interest and incentive distribution rights of the departing general partner and its affiliates for a cash payment equal to the fair market value of those interests. Under all other circumstances where our general partner withdraws, the departing general partner will have the option to require the successor general partner to purchase the general partner interest and the incentive distribution rights of the departing general partner and its affiliates for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value. Or, if the departing general partner and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner's general partner interest and all its and its affiliates' incentive distribution rights will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred as a result of the termination of any employees employed for our benefit by the departing general partner or its affiliates.

Transfer of General Partner Interest

At any time, our general partner may transfer all or any of its general partner interest to another person without the approval of our common unitholders. As a condition of this transfer, the transferee must, among other things, assume the rights and duties of our general partner, agree to be bound by the provisions of our partnership agreement and furnish an opinion of counsel regarding limited liability and tax matters.

Transfer of Ownership Interests in the General Partner

At any time, the owner of our general partner may sell or transfer all or part of its ownership interests in our general partner to an affiliate or third party without the approval of our unitholders.

Transfer of Subordinated Units and Incentive Distribution Rights

By transfer of subordinated units or incentive distribution rights in accordance with our partnership agreement, each transferee of subordinated units or incentive distribution rights will be admitted as a limited partner with respect to the subordinated units or incentive distribution rights transferred when such transfer and admission is reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;
- automatically becomes bound by the terms and conditions of our partnership agreement; and
- gives the consents, waivers and approvals contained in our partnership agreement, such as the approval of all transactions and agreements we entered into in connection with our formation.

Our general partner will cause any transfers to be recorded on our books and records no less frequently than quarterly.

We may, at our discretion, treat the nominee holder of subordinated units or incentive distribution rights as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Subordinated units and incentive distribution rights are securities and any transfers are subject to the laws governing transfer of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a limited partner for the transferred subordinated units or incentive distribution rights.

Until a subordinated unit or incentive distribution right has been transferred on our books, we and the transfer agent may treat the record holder of the unit or right as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove OMP GP as our general partner or from otherwise changing our management. Please read "—Withdrawal or Removal of Our General Partner" for a discussion of certain consequences of the removal of our general partner. If any person or group, other than our general partner and its affiliates, acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to any person or group that acquires the units from our general partner or its affiliates or any transferees of that person or group who are notified by our general partner that they will not lose their voting rights or to any person or group who acquires the units with the prior approval of the board of directors of our general partner. Please read "—Meetings; Voting."

Election to be Treated as a Corporation

If, in connection with the enactment of U.S. federal income tax legislation or a change in the official interpretation of existing U.S. federal income tax legislation by a governmental authority, our general partner determines that (i) we should no longer be characterized as a partnership for U.S. federal or applicable state and local income tax purposes or (ii) common units held by unitholders other than our general partner and its affiliates should be converted into or exchanged for interests in a newly formed entity taxed as a corporation or an entity taxable at the entity level for U.S. federal or applicable state and local income tax purposes whose sole asset is interests in us ("parent corporation"), then our general partner may, without unitholder approval, cause us to be treated as an entity taxable as a corporation or subject to entity-level taxation for U.S. federal or applicable state and local income tax purposes, whether by our election or conversion or by any other means or methods, or cause the common units held by unitholders other than the general partner and its affiliates to be converted into or exchanged for interests in the parent corporation. Any such event may be taxable or nontaxable to our unitholders, depending on the form of the transaction. The tax liability, if any, of a unitholder as a result of such an event may vary depending on the unitholder's particular situation and may vary from the tax liability of our general partner and of our sponsor. In addition, if our general partner causes partnership interests in us to be held by a parent corporation, our sponsor may choose to retain its partnership interests in us rather than convert its partnership interests into parent corporation shares and our general partner may permit other holders to retain their partnership interests in us on a case by case basis. However, our general partner will have no duty or obligation to make any such determination or take any such steps and may decline to do so free of any duty or obligation whatsoever to us or our limited partners, including any duty to act in the best interests of us or our limited partners.

Limited Call Right

If at any time our general partner and its affiliates (including Oasis Petroleum) own more than 80% of the then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the limited partner interests of the class held by unaffiliated persons, as of a record date to be selected by our general partner, on at least 10, but not more than 60, days' notice.

The purchase price in the event of this purchase is the greater of:

- the highest price paid by our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and
- the average of the daily closing prices of the partnership securities of such class over the 20 trading days preceding the date that is three days before the date the notice is mailed.

As a result of our general partner's right to purchase outstanding limited partner interests, a holder of limited partner interests may have his limited partner interests purchased at an undesirable time or at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market.

Non-Taxpaying Holders; Redemption

To avoid any adverse effect on the maximum applicable rates chargeable to customers by us or any of our future subsidiaries, or in order to reverse an adverse determination that has occurred regarding such maximum rate, our partnership agreement provides our general partner the power to amend our partnership agreement. If our general partner, with the advice of counsel, determines that our not being treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes, coupled with the tax status (or lack of proof thereof) of one or more of our limited partners (or their owners, to the extent relevant), has, or is reasonably likely to have, a material adverse effect on the maximum applicable rates chargeable to customers by us or our subsidiaries, then our general partner may adopt such amendments to our partnership agreement as it determines necessary or advisable to:

- obtain proof of the federal income tax status of our limited partners (and their owners, to the extent relevant); and

- permit us to redeem the units held by any person whose tax status has or is reasonably likely to have a material adverse effect on the maximum applicable rates or who fails to comply with the procedures instituted by our general partner to obtain proof of such person's federal income tax status. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption.

Non-Citizen Assignees; Redemption

If our general partner, with the advice of counsel, determines we are subject to federal, state or local laws or regulations that, in the reasonable determination of our general partner, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner (or its owners, to the extent relevant), then our general partner may adopt such amendments to our partnership agreement as it determines necessary or advisable to:

- obtain proof of the nationality, citizenship or other related status of our limited partners (or their owners, to the extent relevant); and

- permit us to redeem the units held by any person whose nationality, citizenship or other related status creates substantial risk of cancellation or forfeiture of any property or who fails to comply with the procedures instituted by the general partner to obtain proof of the nationality, citizenship or other related status. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption.

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units then outstanding, record holders of units on the record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited.

Our general partner does not anticipate that any meeting of our unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of units necessary to authorize or take that action at a meeting. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called, represented in person or by proxy, will constitute a quorum, unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage. Our general partner may postpone any meeting of unitholders one or more times for any reason by giving notice to the unitholders entitled to vote at such meeting. Our general partner may also adjourn any meeting of unitholders one or more times for any reason, including the absence of a quorum, without a vote of the unitholders.

Each record holder of a unit has a vote according to his percentage interest in us, although additional limited partner interests having special voting rights could be issued. Please read "—Issuance of Additional Interests." However, if at any time any person or group, other than our general partner and its affiliates (including Oasis Petroleum), or a direct or subsequently approved transferee of our general partner or its affiliates and purchasers specifically approved by our general partner, acquires, in the aggregate, beneficial ownership of 20% or more of any class of units then outstanding, that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. Common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise. Except as our partnership agreement otherwise provides, subordinated units will vote together with common units, as a single class.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record common unitholders under our partnership agreement will be delivered to the record holder by us or by the transfer agent.

Voting Rights of Incentive Distribution Rights

If a majority of the incentive distribution rights are held by our general partner and its affiliates, the holders of the incentive distribution rights will have no right to vote in respect of such rights on any matter, unless otherwise required by law, and the holders of the incentive distribution rights shall be deemed to have approved any matter approved by our general partner.

If less than a majority of the incentive distribution rights are held by our general partner and its affiliates, the incentive distribution rights will be entitled to vote on all matters submitted to a vote of unitholders, other than amendments and other matters that our general partner determines do not adversely affect the holders of the incentive distribution rights in any material respect. On any matter in which the holders of incentive distribution rights are entitled to vote, such holders will vote together with the subordinated units, prior to the end of the subordination period, or together with the common units, thereafter, in either case as a single class, and such incentive distribution rights shall be treated in all respects as subordinated units or common units, as applicable, when sending notices of a meeting of our limited partners to vote on any matter (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under our partnership agreement. The relative voting power of the holders of the incentive distribution rights and the subordinated units or common units, depending on which class the holders of incentive distribution rights are voting with, will be set in the same proportion as cumulative cash distributions, if any, in respect of the incentive distribution rights for the four consecutive quarters prior to the record date for the vote bears to the cumulative cash distributions in respect of such class of units for such four quarters.

Status as Limited Partner

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission are reflected in our books and records. Except as described under "—Limited Liability," the common units will be fully paid, and unitholders will not be required to make additional contributions.

Books and Reports

Our general partner is required to keep appropriate books of our business at our principal offices. These books will be maintained for both tax and financial reporting purposes on an accrual basis. For tax and fiscal reporting purposes, our fiscal year is the calendar year.

We will furnish or make available to record holders of our common units, within 105 days after the close of each fiscal year, an annual report containing audited financial statements and a report on those financial statements by our independent public accountants. Except for our fourth quarter, we will also furnish or make available summary financial information within 50 days after the close of each quarter. We will be deemed to have made any such report available if we file such report with the SEC on EDGAR or make the report available on a publicly available website that we maintain.

We will furnish each record holder with information reasonably required for federal and state tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to our unitholders will depend on their cooperation in supplying us with specific information. Every unitholder will receive information to assist him in determining his federal and state tax liability and in filing his federal and state income tax returns, regardless of whether he supplies us with the necessary information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable written demand stating the purpose of such demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each record holder;
- copies of our partnership agreement, our certificate of limited partnership, related amendments and powers of attorney under which they have been executed; and
- information regarding the status of our business and our financial condition (provided that this obligation shall be satisfied if the limited partner is furnished our most recent annual report and any subsequent quarterly or periodic reports required to be filed, or which would be required to be filed, with the SEC pursuant to Section 13 of the Securities Exchange Act of 1934, as amended).

Under our partnership agreement, however, each of our limited partners and other persons who acquire interests in our partnership interests, do not have rights to receive information from us or any of the persons we indemnify under the terms of our partnership agreement for the purpose of determining whether to pursue litigation or assist in pending litigation against us or those indemnified persons relating to our affairs, except pursuant to the applicable rules of discovery relating to the litigation commenced by the person seeking information.

Our general partner may, and intends to, keep confidential from the limited partners, trade secrets or other information the disclosure of which our general partner determines is not in our best interests or that we are required by law or by agreements with third parties to keep confidential. Our partnership agreement limits the rights to information that a limited partner would otherwise have under Delaware law.

Registration Rights

Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units, subordinated units or other limited partner interests proposed to be sold by our general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of our general partner. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts.

In addition, in connection with the completion of our IPO, we entered into a registration rights agreement with Oasis Petroleum. Pursuant to the registration rights agreement, we are required to file a registration statement to register the common units and subordinated units issued to Oasis Petroleum and the common units issuable upon the conversion of the subordinated units upon request of Oasis Petroleum. Pursuant to the registration rights agreement and our partnership agreement, we may be required to undertake a future public or private offering and use the proceeds (net of underwriting or placement agency discounts, fees and commissions, as applicable) to redeem an equal number of common units from them. In addition, the registration rights agreement gives Oasis Petroleum “piggyback” registration rights under certain circumstances. The registration rights agreement also includes provisions dealing with holdback agreements, indemnification and contribution and allocation of expenses. These registration rights are transferable to affiliates of Oasis Petroleum and, in certain circumstances, to third parties.

LIMITED LIABILITY COMPANY AGREEMENT
OF
PANTHER DEVCO LLC

a Delaware limited liability company

THIS LIMITED LIABILITY COMPANY AGREEMENT, effective as of May 9, 2019 (this "***Agreement***"), is adopted, executed and agreed to by OMP Operating LLC, a Delaware limited liability company (the "***Sole Member***").

1. ***Formation.*** Panther DevCo LLC (the "***Company***") has been formed as a Delaware limited liability company under and pursuant to the Delaware Limited Liability Company Act (the "***Act***"). This Agreement shall be deemed to have become effective upon the formation of the Company.

2. ***Term.*** The Company shall have perpetual existence.

3. ***Purposes.*** The purpose and nature of the business to be conducted by the Company shall be to engage directly in, or enter into or form, hold and dispose of any corporation, partnership, joint venture, limited liability company or other arrangement to engage indirectly in, any business activity that lawfully may be conducted by a limited liability company organized pursuant to the Act and, in connection therewith, to exercise all of the rights and powers conferred upon the Company pursuant to the agreements relating to such business activity, and to do anything necessary or appropriate to effect the foregoing.

4. ***Members; Membership Interests; Liabilities of Members.*** The Sole Member shall be the sole member of the Company. The membership interest of the Sole Member is set forth on <u>Exhibit A</u> (the "***Membership Interest***"). The debts, obligations and liabilities of the Company, whether arising in contract, tort or otherwise, shall be solely the debts, obligations and liabilities of the Company and the Sole Member shall not be obligated for any such debt, obligation or liability of the Company. The failure to observe any formalities relating to the business or affairs of the Company shall not be grounds for imposing personal liability on the Sole Member for the debts, obligations or liabilities of the Company.

5. ***Contributions.*** The Sole Member has made, or will make, an initial contribution to the capital of the Company in the amount of $1,000 in exchange for the Membership Interest. Without creating any rights in favor of any third party, the Sole Member may, from time to time, make additional contributions of cash or property to the capital of the Company, but shall have no obligation to do so.

6. ***Allocations***. All items of income, gain, loss, deduction and credit of the Company shall be allocated to the Sole Member.

7. ***Distributions.*** The Sole Member shall be entitled (a) to receive all distributions (including, without limitation, liquidating distributions) made by the Company, and (b) to enjoy all other rights, benefits and interests in the Company.

8. ***Management.*** In accordance with Section 18-402 of the Act, management of the Company shall be vested in the Sole Member. The Sole Member shall have the power to do any and all acts necessary, convenient or incidental to or for the furtherance of the purposes described herein, including all powers, statutory or otherwise, possessed by members of a limited liability company under the laws of the State of Delaware. Notwithstanding any other provision of this Agreement, the Sole Member has the authority to bind the Company and is authorized to execute and deliver any document on behalf of the Company without any vote or consent of any other person or entity**.**

9. ***Officers*****.** The Sole Member may, from time to time, designate one or more persons to be officers of the Company (an "***Officer***") on such terms and conditions as the Sole Member may determine. To the fullest extent permitted by law, Officers are not "managers," as that term is used in the Act. Any Officer so designated shall have such title and authority and perform such duties as the Sole Member may, from time to time, designate. Unless the Sole Member decides otherwise, if the title assigned to an Officer is one commonly used for officers of a business corporation formed under the General Corporation Law of the State of Delaware, the assignment of such title shall constitute the delegation to such Officer of the authority and duties that are normally associated with that office, subject to any specific delegation of authority and duties made to such Officer by the Sole Member. Each Officer shall hold office until his successor shall be duly designated and qualified or until his death or until he shall resign or shall have been removed. The salaries or other compensation, if any, of the Officers and agents of the Company shall be fixed from time to time by the Sole Member. Any Officer may resign as such at any time. The Sole Member may delegate to any Officer any of the Sole Member's powers under this Agreement, including, without limitation, the power to bind the Company. Any delegation pursuant to this Section 9 may be revoked at any time by the Sole Member. Any Officer may be removed as such, with or without cause, by the Sole Member at any time. Designation of an Officer shall not, in and of itself, create contractual rights.

10. ***Exculpation; Indemnification*****.** Notwithstanding any other provisions of this Agreement, whether express or implied, or any obligation or duty at law or in equity, neither the Sole Member, nor any officers, directors, stockholders, partners, employees, affiliates, representatives or agents of the Sole Member, or any manager, officer, employee, representative or agent of the Company (individually, a "***Covered Person***" and, collectively, the "***Covered Persons***") shall be liable to the Company or any other person for any act or omission (in relation to the Company, its property or the conduct of its business or affairs, this Agreement, any related document or any transaction or investment contemplated hereby or thereby) taken or omitted by a Covered Person in the reasonable belief that such act or omission is in or is not contrary to the best interests of the Company and is within the scope of authority granted to such Covered Person by the Company, provided such act or omission does not constitute fraud, willful misconduct, bad faith or gross negligence. To the fullest extent permitted by law, the Company shall indemnify and hold harmless each Covered Person from and against any and all civil, criminal, administrative or investigative losses, claims, demands, liabilities, expenses, judgments, fines, settlements and other amounts arising from any and all claims, demands, actions, suits or proceedings ("***Claims***"), in which the Covered Person may be involved, or threatened to be involved, as a party or otherwise, by reason of its management of the affairs of

the Company or which relates to or arises out of the Company or its property, business or affairs. A Covered Person shall not be entitled to indemnification under this Section 10 with respect to (i) any Claim with respect to which such Covered Person has engaged in fraud, willful misconduct, bad faith or gross negligence or (ii) any Claim initiated by such Covered Person unless such Claim (or part thereof) (A) was brought to enforce such Covered Person's rights to indemnification hereunder or (B) was authorized or consented to by the Sole Member. Expenses incurred by a Covered Person in defending any Claim shall be paid by the Company in advance of the final disposition of such Claim upon receipt by the Company of an undertaking by or on behalf of such Covered Person to repay such amount if it shall be ultimately determined that such Covered Person is not entitled to be indemnified by the Company as authorized by this Section 10.

11. ***Dissolution.*** The Company shall dissolve and its affairs shall be wound up at such time, if any, as the Sole Member may elect. No other event will cause the Company to dissolve.

12. ***Governing Law*.** THIS AGREEMENT IS GOVERNED BY AND SHALL BE CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF DELAWARE (EXCLUDING ITS CONFLICT-OF-LAWS RULES).

13. ***Amendments*.** This Agreement may be modified, altered, supplemented or amended at any time by a written agreement executed and delivered by the Sole Member.

[*Signature Page Follows*]

IN WITNESS WHEREOF, the undersigned, being the Sole Member of the Company, has caused this Agreement to be duly executed, effective as of the date first set forth above.

OMP Operating LLC
Sole Member

By: /s/ Nickolas J. Lorentzatos
Name: Nickolas J. Lorentzatos
Title: Executive Vice President, General Counsel

EXHIBIT A

Member	**Membership Interest**
OMP Operating LLC	100%

Exhibit 21.1

List of Subsidiaries of Oasis Midstream Partners LP

Name of Subsidiary	Jurisdiction of Incorporation or Organization
OMP Operating LLC	Delaware
Panther DevCo LLC	Delaware
Bighorn DevCo LLC	Delaware
Bobcat DevCo LLC	Delaware
Beartooth DevCo LLC	Delaware

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-227647) and Form S-8 (No. 333-220627 and No. 333-227174) of Oasis Midstream Partners LP of our report dated February 26, 2020 relating to the financial statements, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 26, 2020

EXHIBIT 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Taylor L. Reid, certify that:

1. I have reviewed this annual report on Form 10-K of Oasis Midstream Partners LP (the "registrant");
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2020

/s/ Taylor L. Reid
Taylor L. Reid
Chief Executive Officer and Director
(Principal Executive Officer)

EXHIBIT 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Richard N. Robuck, certify that:

1. I have reviewed this annual report on Form 10-K of Oasis Midstream Partners LP (the “registrant”);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 26, 2020

/s/ Richard N. Robuck

Richard N. Robuck
Senior Vice President and Chief Financial Officer
(Principal Accounting Officer and Principal Financial Officer)

EXHIBIT 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Oasis Midstream Partners LP (the “Partnership”) on Form 10-K for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Taylor L. Reid, Chief Executive Officer and Director of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 26, 2020

/s/ Taylor L. Reid

Taylor L. Reid
Chief Executive Officer and Director
(Principal Executive Officer)

EXHIBIT 32.2

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Oasis Midstream Partners LP (the "Partnership") on Form 10-K for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Richard N. Robuck, Senior Vice President and Chief Financial Officer of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 26, 2020

/s/ Richard N. Robuck
Richard N. Robuck
Senior Vice President and Chief Financial Officer
(Principal Accounting Officer and Principal Financial Officer)