

Cypress Energy Partners, L.P.
Form 10-K
March 18, 2019

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(MARK ONE)

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

For the fiscal year ended December 31, 2018

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

FOR THE TRANSITION PERIOD FROM_____ TO_____

Commission File No. 001-36260

CYPRESS ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of incorporation or organization)

61-1721523

(I.R.S. Employer Identification No.)

5727 South Lewis Avenue, Suite 300

Tulsa, Oklahoma

74105

(Address of principal executive offices) (Zip Code)

(Registrant's telephone number, including area code): **(918) 748-3900**

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

Common Units Representing Limited Partner Interests
(Title of each class)

New York Stock Exchange
(Name of each exchange on which registered)

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 and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated

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filer,” “smaller reporting company” and “emerging growth company” in Rule 12b-2 of the Exchange Act. (Check one):

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

The aggregate market value of the registrant’s Common Units Representing Limited Partner Interests held by non-affiliates computed by reference to the price at which the limited partner units were last sold as of June 30, 2018 was \$31,149,538.

As of March 11, 2019, the registrant had 12,023,170 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

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GLOSSARY OF TERMS

The following includes a description of the meanings of some of the terms used in this Annual Report on Form 10-K.

<i>“Dig site”</i>	The location where pipeline maintenance occurs by excavating the ground above the pipeline.
<i>“Flowback water”</i>	The fluid that returns to the surface during and for the weeks following the hydraulic fracturing process.
<i>“Gun barrel”</i>	A settling tank used for treating oil where oil and brine are separated only by gravity segregation forces.
<i>“Hydraulic fracturing”</i>	The process of pumping fluids, mixed with granular proppant, into a geological formation at pressures sufficient to create fractures in the hydrocarbon-bearing rock.
<i>“Hydrotesting”</i>	A process in which pressure vessels such as pipelines and fuel tanks can be tested for strength and leaks by filling the vessel with a liquid and pressurizing the vessel to the specified test pressure.
<i>“In-line inspection”</i>	An inspection technique used to assess the integrity of natural gas transmission pipelines from inside of the pipe.
<i>“IPO”</i>	Our initial public offering of common units representing limited partner interests in us.
<i>“Injection intervals”</i>	The part of the injection zone in which the well is screened or in which the waste is otherwise directly emplaced.
<i>“Natural gas liquids”</i>	The combination of ethane, propane, butane, isobutene and natural gasolines that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.
<i>“OPEC”</i>	The Organization of Petroleum Exporting Countries.
<i>“Pig tracking”</i>	The locating, mapping and monitoring of the in-line inspection pig.
<i>“Pipeline & Process Services”</i>	Our Pipeline & Process Services (formerly referred to as our Integrity Services) business segment.
<i>“Pipeline Inspection”</i>	Our Pipeline Inspection business segment.
<i>“Produced water”</i>	Naturally occurring water found in hydrocarbon-bearing formations that flows to the surface along with oil and natural gas.
<i>“Proppant”</i>	

Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment.

“Residual oil” Oil separated and recovered during the saltwater treatment process.

“Separation tank” A cylindrical or spherical vessel used to separate oil, gas and water from the total fluid stream produced by a well.

“Settling tank” A non-circulating storage tank where gravitational segregation forces separate liquids from solids.

“Staking” The process of marking the location where pipeline maintenance will occur.

“SWD” Saltwater disposal.

“Water Services” Our Water and Environmental Services business segment.

NAMES OF ENTITIES

Unless the context otherwise requires, references in this Annual Report on Form 10-K to “Cypress Energy Partners, L.P.,” “our partnership,” “we,” “our,” “us,” or like terms, refer to Cypress Energy Partners, L.P. and its subsidiaries.

References to:

“*Brown*” refers to Brown Integrity, LLC, a 51% owned subsidiary of CEP LLC acquired May 1, 2015;

“*CEM LLC*” refers to Cypress Energy Management, LLC, a wholly owned subsidiary of the General Partner;

“*CEM TIR*” refers to Cypress Energy Management – TIR, LLC, a wholly owned subsidiary of CEM LLC;

“*CEP LLC*” refers to Cypress Energy Partners, LLC, a wholly owned subsidiary of the Partnership;

“*CEP-TIR*” refers to Cypress Energy Partners – TIR, LLC, an indirect subsidiary of Holdings, and an owner of 1,346,800 common units representing 11.2% of our outstanding common units as of March 11, 2019, and an owner of a 36.2% interest in the TIR Entities prior to the sale of its interests to the Partnership effective February 1, 2015;

“*CF Inspection*” refers to CF Inspection Management, LLC, owned 49% by TIR-PUC and consolidated under generally accepted accounting principles by TIR-PUC. CF Inspection is 51% owned, managed and controlled by Cynthia A. Field, an affiliate of Holdings and a Director of our Partnership;

“*General Partner*” refers to Cypress Energy Partners GP, LLC, a subsidiary of Cypress Energy GP Holdings, LLC;

“*Holdings*” refers to Cypress Energy Holdings, LLC, the owner of Holdings II;

“*Holdings II*” refers to Cypress Energy Holdings II, LLC, the owner of 5,610,549 common units representing 46.7% of our outstanding common units as of March 11, 2019;

“*Partnership*” refers to the registrant, Cypress Energy Partners, L.P.;

“*TIR Entities*” refer collectively to TIR LLC; TIR-Canada, TIR-NDE, TIR-PUC and CF Inspection;

“*TIR-NDE*” refers to Tulsa Inspection Resources – Nondestructive Examination, LLC, a wholly-owned subsidiary of CEP LLC;

“*TIR-Canada*” refers to Tulsa Inspection Resources – Canada, ULC, a wholly owned subsidiary of CEP LLC;

“*TIR LLC*” refers to Tulsa Inspection Resources, LLC, a wholly owned subsidiary of CEP LLC;

“*TIR-PUC*” refers to Tulsa Inspection Resources – PUC, LLC, a subsidiary of TIR LLC that has elected to be treated as a corporation for U.S. federal income tax purposes.

CAUTIONARY REMARKS REGARDING FORWARD LOOKING STATEMENTS

The information discussed in this Annual Report on Form 10-K includes “forward-looking statements.” These forward-looking statements are identified by their use of terms and phrases such as “may,” “expect,” “estimate,” “project,” “plan,” “believe,” “intend,” “achievable,” “anticipate,” “continue,” “potential,” “should,” “could,” and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties and we can give no assurance that such expectations or assumptions will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements are described under “*Item 1A - Risk Factors*” and “*Item 7 - Management’s Discussion and Analysis of Financial Condition and Results of Operations*” in this Annual Report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this Annual Report on Form 10-K and speak only as of the date of this Annual Report on Form 10-K. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

PART I

ITEM 1. BUSINESS

Overview

The Partnership is a Delaware limited partnership formed on September 19, 2013 to become a diversified Partnership serving energy companies throughout North America. We completed our initial public offering in January 2014. We currently provide essential midstream services that include independent pipeline inspection and integrity services to producers and pipeline companies and water and environmental services to U.S. onshore oil and natural gas producers and trucking companies.

Our business is organized into three reportable segments: (1) Pipeline Inspection Services (“Pipeline Inspection”), comprising the TIR Entities’ operations, (2) Pipeline & Process Services (“Pipeline & Process Services”), made up of Brown’s operations and (3) Water and Environmental Services (“Water Services”), constituting saltwater disposal activities in our saltwater disposal entities. Other potential lines of business outlined in U.S. Treasury Regulations and our Internal Revenue Service (“IRS”) private letter ruling (“PLR”) would allow us to further diversify our business activities and lines of business serving the energy industry.

The Pipeline Inspection segment generates revenue primarily by providing essential inspection and integrity services on a variety of infrastructure assets, including midstream pipelines, gathering systems, and distribution systems. Services include non-destructive examination, mechanical integrity, survey, data gathering, and supervision of third-party contractors. Our results in this segment are driven primarily by the number of inspectors that perform services for our customers and the fees that we charge for those services, which depend on the type, skills, technology, equipment, and number of inspectors used on a particular project, the nature of the project, and the duration of the project. The number of inspectors engaged on projects is driven by the type of project, prevailing market rates, the age and condition of customers' assets including pipelines, gas plants, compression stations, storage facilities, and gathering and distribution systems, including the legal and regulatory requirements relating to the inspection and maintenance of those assets. Our customers are also billed for per diem charges, mileage, and other reimbursement items. Revenue and costs in this segment may be subject to seasonal variations and interim activity may not be indicative of yearly activity, considering many of our customers develop yearly operating budgets and enter into contracts with us during the winter season for work to be performed during the remainder of the year. Additionally, inspection work throughout the United States during the winter months (especially in the northern states) may be hampered or delayed due to inclement weather, thus affecting our revenue and costs.

The Pipeline & Process Services segment (formerly our Integrity Services segment) generates revenue primarily by providing essential midstream services including hydrostatic testing services and chemical cleaning related to newly-constructed and existing pipelines and related infrastructure. We generally charge our customers in this segment on a fixed-bid basis, depending on the size and length of the pipeline being tested, the complexity of services provided, and the utilization of our work force and equipment. Our results in this segment are driven primarily by the number of field personnel that perform services for our customers and the fees that we charge for those services, which depend on the type and number of field personnel used on a particular project, the type of equipment used and the fees charged for the utilization of that equipment, and the nature and duration of the project.

The Water Services segment owns and operates nine (9) Environmental Protection Agency Class II saltwater disposal facilities in the Williston Basin region of North Dakota. Eight (8) of the facilities are wholly-owned and we have ten (10) pipelines from multiple E&P customers connected to these saltwater disposal facilities, including two (2) that were developed and are owned by the Partnership. Approximately 94% of our disposal water is produced water that is generated during the production life of an oil and gas well and 45% of our water is delivered via pipeline to our saltwater disposal facilities. We currently serve approximately 86 customers. Our saltwater disposal facilities provide essential midstream services to oil and natural gas upstream producers and their transportation companies. All of the saltwater disposal facilities utilize specialized equipment and remote monitoring to minimize the facilities' downtime and increase the facilities' efficiency for peak utilization. These facilities also utilize oil skimming and recovery processes that remove residual oil from water delivered to our saltwater disposal facilities via pipeline or truck. We sell the oil recovered from these skimming processes, which contributes to our revenues. In addition to these saltwater disposal facilities, we provide management and staffing services to a saltwater disposal facility in which we own a 25% ownership interest.

Our Relationship with Cypress Energy Holdings, LLC

All of the equity interests in our general partner are indirectly owned by Holdings and its affiliates. Holdings is owned by Charles C. Stephenson, Jr.; entities related to Mr. Stephenson's family; Cynthia A. Field; a company controlled by our Chairman, Chief Executive Officer and President, Peter C. Boylan III; Henry Cornell; and a company controlled by Mr. Cornell. Holdings' owners bring substantial industry relationships and specialized, value-creation capabilities that we believe continue to benefit us. Mr. Stephenson has over 50 years of experience as a leader in the oil and natural gas industry. He was the founder, Chairman and Chief Executive Officer of Vintage Petroleum prior to its sale to Occidental Petroleum in 2006 and is also the retired Chairman of Premier Natural Resources, a private oil and natural gas exploration and production company that he co-founded. Mr. Boylan has extensive executive management experience with public and private companies and also has extensive public company directorship experience. As the owners of our general partner and the direct or indirect owners of 64.1% of our outstanding common units and all of our outstanding preferred units, Holdings and its affiliates have a strong alignment of interests with our minority unitholders to ensure the ongoing successful execution of our business plan.

Business Strategies

Our principal business objective is to build a diversified partnership serving energy customers that will allow us, over time, to incrementally increase the quarterly cash distributions that we pay to our unitholders. We expect to achieve this objective through the following business strategies:

Pipeline Inspection. We believe the pipeline inspection services market offers attractive long-term growth fundamentals; as such, we intend to continue to position ourselves as a trusted provider of high-quality essential inspection services. Over the last few years, new laws have been enacted in the U.S. that, in the future, will require operators to undertake more frequent and more extensive inspections of their pipeline assets. These requirements are not tied to the current state of the oil and gas industry as a whole. Additionally, a significant portion of the pipeline infrastructure in North America was installed decades ago and is therefore more susceptible to material degradation requiring more frequent inspections. We believe that increasingly stringent U.S. federal and state laws and regulations and aging pipeline infrastructures will result in increased need for inspection and integrity services and higher demand for independent, third-party inspectors capable of navigating these complicated requirements. Most of our clients are investment-grade, well-capitalized companies that have long lead time projects that require our services regardless of the state of the current economy. Our clients also require ongoing maintenance and integrity work on their aging pipelines. Our business is not immune to changes in the energy economy; however, we believe that we can continue to grow organically by acquiring new customers and additional work from existing customers. We continue to grow our business development team to pursue these and other opportunities.

Pipeline & Process Services. We experienced significant improvements in our utilization rates in this segment during 2018, after a difficult two-year period during the industry downturn. Improvements were due, in part, to increasing demand and, in part, to improved business development efforts. During 2018, we opened a new office in Odessa, Texas, to better serve the growing Permian basin market. In addition, we added several industry

veterans to our management team in order to further enhance our image and grow the segment. In early 2019, an affiliated entity opened a new location in the Houston market to help us take advantage of the growing work in the industry. This segment had two difficult years during the energy industry downturn, which forced us to implement aggressive measures to manage and reduce its cost structure. We believe these measures were successful, and we plan to continue to focus on the potential synergies that may develop between this segment and our other business segments. We continue to enjoy an excellent reputation in the industry and continue to bid on a substantial amount of new work.

Water Services. We believe that the water and environmental services market will continue to offer long-term growth fundamentals and we intend to maintain our position as a high-quality operator of saltwater disposal facilities. We took aggressive actions in 2016 to adjust our cost structure to compensate for the lower volumes associated with the industry downturn. We continue to look for pipeline opportunities with exploration and production (“E&P”) companies that will secure water for our saltwater disposal facilities. Regulations continue to increase and we have proven to our customers that we are a trusted and dependable service provider. Increasingly, E&P companies are having their central procurement and Environment, Health and Safety (“EHS”) personnel conduct inspections of saltwater disposal facilities. This trend should benefit us. We remain an approved vendor for many prestigious investment grade E&P companies that demand very high standards from their vendors. Although the oil and gas industry can be cyclical in nature, our current business strategy is to derive a significant portion of our volume and revenue from existing wells. We intend to capitalize on the continued demand for removal, treatment, storage and disposal of flowback and produced water by positioning ourselves as a trusted, dependable provider of safe, high-quality water and environmental services to our energy customers.

Optimize existing saltwater disposal assets. The average age of our saltwater disposal facilities was 6.3 years at the end of 2018. We estimate that we utilized approximately 42% of the aggregate annual capacity (35.3 million barrels per year) of these facilities for the year ended December 31, 2018, evidencing capacity for growth without additional capital expenditures. We are seeking to increase the utilization of our existing saltwater disposal facilities by attracting new volumes from existing customers and by developing new customer relationships, including pipelines. In 2012, only one pipeline was directly connected to our saltwater disposal facilities. We currently have ten pipelines connected to four of our saltwater disposal facilities. Because many of the costs of constructing and operating a saltwater disposal facility are either upfront capital costs or fixed costs, we expect that increased utilization of our existing saltwater disposal facilities will lead to increased operating cash flow in the Water Services segment. The multi-year industry downturn placed significant pressure on both the volumes we processed and the prices we were able to charge for our services, however, the industry began a recovery following OPEC's decision to reduce production in November 2016.

Increase the number of pipelines connected to our saltwater disposal facilities. As more oil and natural gas producers focus on improving operational safety and reducing liability, carbon footprint, road damage, and the total transportation cost associated with the trucking of saltwater, we anticipate that natural gas producers will increasingly prefer to utilize pipeline systems to transport their saltwater directly to saltwater disposal facilities. We continue to focus on increasing pipeline water delivered to our facilities. Our 2018 pipeline water volumes increased approximately 0.7 million barrels from piped water volumes in 2017. As a percentage of total water volume, pipeline water was 45%, 46% and 45% in 2018, 2017 and 2016, respectively. We will continue to focus on potential pipeline opportunities. For example, in January 2018, we completed the construction of two pipelines that transport water from a customer's producing fields to one of our disposal facilities.

Leverage customer relationships in our business segments. We intend to pursue new strategic development opportunities with oil and natural gas producing customers that increase the utilization of our assets and lead to cross-selling opportunities between our business segments. Many customers of Water Services also own gathering systems, storage facilities, gas plants, compression stations, and other pipeline assets to which we can offer pipeline inspection and integrity services. In addition, we intend to enhance our relationships with our customers in the Pipeline Inspection segment by broadening the services we provide to our customers, including expanding our ultrasonic nondestructive examination services. By cross-selling our service offerings and adding complementary service offerings, we believe that we can further integrate into our customers' operations and increase our profitability and distributable cash flow.

Pursue strategic, accretive acquisitions. Our sponsor, Holdings, completed two acquisitions in the third quarter of 2018 that we believe will allow us to expand the breadth and depth of the pipeline integrity services we offer to our clients. Both transactions were asset purchases that require some repositioning before bringing them into the Partnership. Holdings made solid progress toward that goal on both acquisitions in the fourth quarter of 2018, and intends to offer them to the Partnership once it has accomplished certain developmental goals, most likely in early 2020 (if not sooner). These acquisitions would move us into several new lines of work, including water treatment, in-line inspection ("ILI") with next-generation high resolution technology for energy companies, equipment rental (which could be converted into a service business before offering this line of business to the Partnership), and other pipeline process services including nitrogen and dehydration. Holdings' new Lafayette facility will also allow us to expand into the offshore market and positions us to better serve the Southeastern part of the country. The acquired ILI technology is also the first high definition tool capable of serving the municipal water industry's aging mortar-lined steel pipelines used to transport drinking water that are in need of substantial maintenance, repair, and replacement. The future acquisitions of these businesses, when appropriate, should also position us to eventually

resume increasing our distributions.

Our Business Segments

Our business operates in three reportable segments: (1) Pipeline Inspection Services (“Pipeline Inspection”), comprising the TIR Entities’ operations, (2) Pipeline & Process Services, made up of Brown’s operations, and (3) Water and Environmental Services (“Water Services”), consisting of saltwater disposal activities. U.S. Treasury Regulations and our IRS private letter ruling (“PLR”) allows for expansion into other lines of business. Our long-term goal continues to be diversifying the Partnership into other attractive lines of business.

Pipeline Inspection

Overview. The Pipeline Inspection segment is a leading provider of independent inspection services to the pipeline industry. We provide essential services for pipelines, gathering systems, local distribution systems, equipment, and facilities to our well-established customer base. We provide inspection to oil and natural gas producers, public utility companies, and other pipeline operators that are required by law to inspect their gathering systems, storage facilities, infrastructure, distribution systems and pipelines. Our Pipeline Inspection service customers include oil and natural gas producers, pipeline owners and operators, and public utility companies throughout the United States. We also have entered into a joint venture with CF Inspection, a nationally-qualified woman-owned inspection firm affiliated with one of Holdings’ owners. CF Inspection serves energy companies that require the services of an approved Women's Business Enterprise. We own 49% of CF Inspection and Cynthia A. Field, a member of our board of directors and the daughter of Charles C. Stephenson, Jr., another member of our board of directors, owns the remaining 51% of CF Inspection. In 2018, CF Inspection represented approximately 3.4% of our consolidated revenue.

Pipeline Inspection offers independent inspection services for the following facilities and equipment:

- Transmission pipelines (oil, gas and liquids);
- Oil and natural gas gathering systems;
- Natural gas processing plants;
- Pump, compressor, measurement, and regulation stations;
- Storage facilities and terminals; and
- Gas distribution systems.

Operations. Oil and natural gas producers, public utility companies, and other pipeline operators are required by federal and state law and regulation to inspect their pipelines and gathering systems on a regular basis in order to

protect the environment and ensure public safety. At the beginning of an engagement, our personnel meet with the customer to determine the scope of the project and determine related staffing needs. We then develop a customized, detailed staffing plan, utilizing our proprietary database of more than 21,000 professionals. Our inspectors have significant industry experience and are certified to meet the qualification requirements of both the customer and the Pipeline and Hazardous Materials Safety Administration (“PHMSA”). As the industry continues to adopt new technology, demand has increased for inspectors with greater technical skills and computer proficiencies. Our customers require inspectors to undergo specific training prior to performing inspection work on their projects. We utilize the National Center for Construction Education and Research and Veriforce training curricula to train and evaluate employees, along with other resources. In addition to assignment-specific training, welding inspectors and coating inspectors also must meet special certification requirements. During the years ended December 31, 2018, 2017 and 2016 we employed an average of 1,214, 1,145 and 1,147 inspectors, respectively, in the U.S. and Canada.

Our scope of services include the following:

Project coordination (construction or maintenance coordination for in-line pipeline inspection projects);

Staking services (marking a dig site for surveyed anomalies);

Pig tracking services (mapping and tracking of third-party pipeline cleaning and inspection units, called pigs);

Maintenance inspection (third-party pipeline periodic inspection to comply with PHMSA regulations);

Construction inspection (third-party new construction inspection/oversight on behalf of owner);

Phased Array Ultrasonic Testing (“PAUT”), Optical Emission Spectroscopy (“OES”) and automated metal loss mapping to detect, map and evaluate pipeline imperfections; and

Related data management services.

Pipeline & Process Services

Overview. The Pipeline & Process Services segment provides hydrostatic testing and related services to the pipeline industry, including major natural gas and petroleum companies, as well as pipeline construction companies. We focus on helping our customers meet regulatory pipeline integrity requirements. Our primary emphasis is on hydrostatic testing projects on new and existing pipelines required to maintain compliance with state and federal regulations. We perform all aspects of pipeline hydrostatic testing including filling, pressure testing, and dewatering. Unique test conditions, such as ultra-high pressure tests and pneumatic or nitrogen testing, are performed on a routine basis as well. We provide services on newly-constructed and existing natural gas and crude oil pipelines.

Operations. Oil and natural gas producers, midstream operators, public utility companies, and other pipeline operators are required by federal and state law to perform routine maintenance on their pipelines and gathering systems on a regular basis. In addition, operators and pipeline construction companies are required to integrity-test newly-constructed pipelines prior to placing the pipelines in service. In our Pipeline & Process Services segment, we contract directly with pipeline owners and with pipeline construction companies to provide testing services. We own and operate our own fill and testing equipment, including specially-designed test trailers. We use a range of fill and pressure equipment to accommodate projects of various sizes. The segment averaged 23, 20 and 23 field technicians performing the testing services during the years ended December 31, 2018, 2017 and 2016, respectively.

Water Services

Overview. The Water Services segment owns and operates nine (9) Environmental Protection Agency Class II saltwater disposal facilities in the Williston Basin region of North Dakota. Eight (8) of the facilities are wholly-owned and we have ten (10) pipelines from multiple E&P customers connected to these saltwater disposal facilities, including two (2) that were developed and are owned by the Partnership. Approximately 94% of our disposal water is produced water that is generated during the production life of an oil and gas well and 45% of our water is delivered via pipeline to our saltwater disposal facilities. We currently serve approximately 86 customers. Our saltwater disposal facilities provide essential midstream services to oil and natural gas upstream producers and their transportation companies. All of our saltwater disposal facilities utilize specialized equipment and remote monitoring to minimize the facilities' downtime and increase the facilities' efficiency for peak utilization. These facilities also utilize oil skimming and recovery processes that remove residual oil from water delivered to our saltwater disposal facilities via pipeline or truck. We sell the oil recovered from these skimming processes, which contributes to our revenues. In addition to these saltwater disposal facilities, we provide management and staffing services to a saltwater disposal facility in which we own a 25% ownership interest.

Operations. Water Services currently generates revenue by providing the following services:

Flowback water management. We dispose of flowback water produced from hydraulic fracturing operations during the completion of oil and natural gas wells. Fracturing fluids, including a significant amount of water and proppant, are injected into the well during the completion process and are partially recovered as flowback water. E&P companies have significantly increased their volumes of completion barrels of water in various formations in order to get higher production yields when the wells are put into production. When it is removed, this flowback water contains sand, salt, chemicals, and residual oil. The oil and natural gas producer typically either transports the flowback water to one of our saltwater disposal facilities via pipeline or by truck, or contracts with a trucking company for transport. Once the water is received at the saltwater disposal facility, we treat the water through a combination of separation tanks, gun barrels, and chemical processes. The water is then injected into the saltwater disposal well at depths of at least 5,000 feet after recovering the skim oil. We also maintain the ability to store saltwater pending injection. Similar to produced water, we assess the composition of flowback water in our facilities so that we can maximize oil separation and treat the water to maximize the life of our equipment and the wellbore. We believe our approach to scientifically and methodically filtering and treating the flowback water prior to injecting it into our wells helps extend the life of our wells and furthers our reputation as an environmentally-conscious service provider.

Produced water management. We dispose of naturally-occurring water that is extracted during the oil and natural gas production process. This produced water is generated during the entire lifecycle of an oil and natural gas well. While the level of hydrocarbon production declines over the life of a well, the amount of saltwater produced may decline at a slower rate or, in some cases, may even increase. The oil and natural gas producer separates the produced water from the production stream and either transports it to one of our saltwater disposal facilities by truck or pipeline, or contracts with a trucking company to transport it to one of our saltwater disposal facilities. Once we receive the water at one of our saltwater disposal facilities, we filter and treat the water and then inject it into the saltwater disposal well at depths of at least 5,000 feet after recovering any skim oil. We also maintain the ability to store saltwater pending injection. All of our existing facilities were constructed using completion

techniques consistent with current industry practices. We periodically sample, test, and assess produced water to determine its chemistry so that we can properly treat the water with the appropriate chemicals that maximize oil separation and the life of our wells.

Byproduct sales. Before we inject flowback and/or produced water into a saltwater disposal well, we separate the residual oil from the saltwater stream. We then store the residual oil in our tanks and sell it to third parties. The residual oil recovery can be significant when substantial drilling and completions occur near our saltwater disposal facilities.

Management of existing saltwater disposal facilities. In addition to the saltwater disposal facilities we own or lease, we own a management and development company that manages an additional saltwater disposal facility in North Dakota. Our responsibilities in managing this saltwater disposal facility typically include operations, billing, collections, insurance, maintenance, repairs and, in some cases, sales and marketing. We are compensated for the management of this facility based on a percentage of the gross revenue of the facility or a minimum monthly fee.

The majority of our disposed saltwater volumes are derived from produced water that is generated throughout the life of the oil or natural gas well. For the years ended December 31, 2018, 2017 and 2016, produced water represented 94%, 93%, and 96%, respectively, of our total barrels of disposed water. This differentiates us from many competitors that focus on flowback water. As a region matures and the predominant activity shifts from drilling and completion of wells to production, our facilities continue to experience demand for ongoing processing of wastewater produced over the life of the wells.

Each of our saltwater disposal facilities is open every day of the year, with some being open by appointment only. Some of our locations include onsite offices and sleeping quarters. We supplement our operations with various automated technologies to improve their efficiency and safety. We have installed 24-hour digital video monitoring and recording systems at each facility. These systems allow us to track operations and unloading activities, as well as to identify customers present at our facilities. We believe that our commitment to operating our facilities with sophisticated technology and automation contributes to our enhanced operating margins and provides our customers with increased safety and regulatory compliance. Our facilities have been inspected and approved by several of our public E&P customers that have stringent approval standards and field audits performed by their Environmental, Health and Safety groups.

We have an aggregate maximum daily disposal capacity of 108,800 barrels in the following saltwater disposal facilities, all of which were built using completion techniques consistent with current industry practices and utilizing well depths of at least 5,300 feet to 6,200 feet with injection intervals beginning at least 5,000 feet beneath the surface. Our permitted capacity is much higher.

Location	County	In-service Date	Leased / Owned (3)
Tioga, ND	Williams	June 2011	Owned
Manning, ND	Dunn	December 2011	Owned
Grassy Butte, ND	McKenzie	May 2012	Leased
New Town, ND (1)	Mountrail	June 2012	Leased
Williston, ND (1)	Williams	August 2012	Owned
Stanley, ND	Mountrail	September 2012	Owned
Belfield, ND	Billings	October 2012	Leased
Watford City, ND (1), (2)	McKenzie	May 2013	Leased
Arnegard, ND (1)	McKenzie	August 2014	Leased

- (1) Currently receives piped water.
We own a 25.0% noncontrolling
(2) interest in this saltwater disposal facility.
Some facilities are constructed on
(3) land that is leased under long-term arrangements.

Principal Customers

Pipeline Inspection

Customers of our Pipeline Inspection segment are principally oil and natural gas producers, pipeline owners and operators, and public utility or local distribution companies with infrastructure in North America. During the years ended December 31, 2018, 2017, and 2016, this segment had approximately 87, 81, and 81 customers, respectively. The five largest customers in this segment generated 51%, 53%, and 62% of our segment revenue for the years ended December 31, 2018, 2017, and 2016, respectively. For the years ended December 31, 2018, 2017, and 2016, we had two, three, and three customers, respectively, that individually accounted for more than 10% of segment revenues.

Pipeline & Process Services

Pipeline & Process Services segment customers are primarily pipeline construction companies and, in some instances, the pipeline owners. During the years ended December 31, 2018, 2017, and 2016, this segment had approximately 49, 51, and 56 customers, respectively. Our ten largest customers generated 78%, 74%, and 71% of our total segment revenue during the years ended December 31, 2018, 2017, and 2016, respectively. We had two customers that each generated more than 10% of the total segment revenues for the years ended December 31, 2018, 2017, and 2016.

Water Services

Water Services segment customers are oil and natural gas E&P companies, including majors and independents, trucking companies and third-party purchasers of residual oil operating in the regions that we serve. In the years ended December 31, 2018, 2017, and 2016, this segment had approximately 86, 95, and 72 customers, respectively. Our ten largest customers generated 68%, 65%, and 65% of the Water Services revenue for the years ended December 31, 2018, 2017, and 2016, respectively. For the years ended December 31, 2018, 2017, and 2016, we had two, one, and two customers, respectively, that individually accounted for more than 10% of segment revenues.

Competition

Pipeline Inspection

The pipeline inspection business is highly competitive. Pipeline Inspection's competition consists primarily of three types of companies: independent energy inspection firms, engineering and construction firms, and diversified inspection service firms. Diversified inspection firms may inspect, for example, electric and nuclear facilities in addition to pipelines and related facilities. We believe that the principal competitive factors in our business include gaining and maintaining customer approval to service their pipelines, facilities and gathering systems, the ability to recruit and retain qualified experienced inspectors with multiple skills and non-destructive examination experience, safety record, insurance, the level of inspector training provided, reputation, dependability of services, customer service, and price.

Pipeline & Process Services

The pipeline and process services business (hydrotesting) is highly competitive. We believe that the principal competitive factors in our business are customer service, safety, and price. Our competition consists primarily of smaller regional integrity firms and pipeline construction companies that pipeline owners allow to test their own construction and repair work.

Water Services

The water services business is highly competitive with relatively low barriers of entry. During 2014, our competitors opened a number of new locations around our existing facilities based upon anticipated new drilling activity prior to a downturn in the oil and gas industry that began in November 2014. Our competition consists primarily of smaller regional companies that utilize a variety of disposal methods and generally serve specific geographical markets. In addition, we face competition from other large oil field service companies that also own trucking operations and competition from our customers, who may have the option of using internal disposal methods instead of outsourcing to us or to another third-party disposal company. Many E&P companies also own their own saltwater disposal facilities and water gathering systems, and therefore do not send their produced water to third parties for disposal. We believe that the principal competitive differentiating factors in our businesses include gaining and maintaining customer approval of saltwater disposal facilities, location of facilities in relation to customer activity, reputation, safety record, reliability of service, track record of environmental and regulatory compliance, customer service, insurance coverage, and price.

Seasonality

Pipeline Inspection

Inspection work varies depending upon the geographic location of our customers. The third and beginning of the fourth quarters are historically the most active for our pipeline inspection services in the United States as our customers focus on completing projects by year-end. Business has historically been slower in the period from November through March, due to the holiday season and the budgeting cycles of our customers. We believe our presence across various regions in the U.S. helps mitigate the seasonality of our business. As we expand our relationships with public utility commissions in California and other locations with moderate climates, our inspection and integrity business could become less seasonal.

Pipeline & Process Services

Since most of the work of the Pipeline & Process Services segment is currently performed in the southern United States, weather does not create significant seasonal variations in revenue. Business has historically been slower in the period from November through March, due to the holiday season and the budgeting cycles of our customers.

Water Services

The overall operations and financial performance of our North Dakota operations are impacted by seasonality. The volume of saltwater that we handle in the Bakken Shale region of the Williston Basin in North Dakota tends to be lower in the winter, due to heavy snow and cold temperatures, and in the spring, due to heavy rains and muddy conditions, that may lead to road restrictions and weight limits that can impact business. The amount of residual oil is also less prevalent and more difficult to separate from the saltwater during the winter months.

Regulation of the Industry

Environmental and Occupational Health and Safety Matters

Our operations and the operations of our customers are subject to numerous federal, state, and local environmental laws and regulations relating to worker health and safety, the discharge of materials, and environmental protection. These laws and regulations may, among other things, require the acquisition of permits for regulated activities; govern the amounts and types of substances that may be released into the environment in connection with our operations; restrict the way we handle or dispose of wastes; limit or prohibit our or our customers' activities in sensitive areas such as wetlands, wilderness areas, or areas inhabited by endangered or threatened species; require investigatory and remedial actions to mitigate pollution conditions caused by our current or former operations; and impose specific standards addressing worker protections. Numerous governmental agencies issue regulations to implement and enforce these laws, for which compliance is often costly and difficult. The violation of these laws and regulations may result in the denial or revocation of permits, issuance of corrective action orders, assessment of administrative and civil penalties, and even criminal prosecution.

We do not anticipate that compliance with existing environmental and occupational health and safety laws and regulations will have a material effect on our Consolidated Financial Statements. However, these rules and regulations are constantly evolving, and amendments thereto could result in a material effect on our operations and financial position. Further, while we may occasionally receive citations from environmental regulatory agencies for minor violations, such citations occur in the ordinary course of our business and are generally not material to our operations. However, it is possible that substantial costs for compliance or penalties for non-compliance may be incurred in the future. It is also possible that other developments, such as the adoption of stricter environmental laws, regulations, and enforcement policies, could result in additional costs or liabilities that we cannot currently quantify. Moreover, changes in environmental laws could limit our customers' businesses or encourage our customers to handle and dispose of oil and natural gas wastes in other ways, which, in either case, could reduce the demand for our services and adversely impact our business.

The following is a summary of the more significant existing environmental and occupational health and safety laws and regulations 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 financial position, results of operations, or future cash flows.

Hazardous substances and wastes. Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid wastes, hazardous wastes, and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid 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. For instance, the Comprehensive Environmental Response Compensation and Liability Act, or CERCLA, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. We may handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. Under such laws, we could be required to remove previously disposed substances and wastes (including substances disposed of or released by prior owners or operators) or remediate contaminated property (including groundwater contamination, whether from prior owners or operators or other historical activities or spills). These laws may also require us to conduct natural resource damage assessments and pay penalties for such damages. It is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. These laws

and regulations may also expose us to liability for our acts that were in compliance with applicable laws at the time the acts were performed.

Petroleum hydrocarbons and other substances arising from oil and natural gas-related activities have been disposed of or released on or under many of our sites. At some of our facilities, we have conducted and continue to conduct monitoring or remediation of known soil and groundwater contamination. We will continue to perform such monitoring and remediation of known contamination, including any post remediation groundwater monitoring that may be required, until the appropriate regulatory standards have been achieved. These monitoring and remediation efforts are usually overseen by state environmental regulatory agencies.

In the future, we may also accept for disposal solids that are subject to the requirements of the federal Resource, Conservation, and Recovery Act, or RCRA, and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation, and disposal of hazardous wastes. Most E&P waste is exempt from stringent regulation as a hazardous waste under RCRA. None of our facilities are currently permitted to accept hazardous wastes for disposal, and we take precautions to help ensure that hazardous wastes do not enter or are not disposed of at our facilities. Some wastes handled by us that currently are exempt from treatment as hazardous wastes may in the future be designated as “hazardous wastes” under RCRA or other applicable statutes. For example, in May 2016, a nonprofit environmental group filed suit in the federal district court for the District of Columbia, seeking a declaratory judgment directing the EPA to review and reconsider the RCRA E&P waste exemption. EPA and the environmental group entered into an agreement that was formalized in a consent decree issued by the U.S. District court for the District of Columbia in December 2016. Under the decree, the EPA is required to propose a rulemaking for revisions of certain of its regulations pertaining to E&P wastes or sign a determination that revision of the regulations is not necessary. If EPA proposes a rulemaking for revised E&P waste regulations, the consent decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. If the RCRA E&P waste exemption is repealed or modified, we could become subject to more rigorous and costly operating and disposal requirements.

We are required to obtain permits for the disposal of E&P waste as part of our operations. These regulations vary widely from state to state. State permits can restrict pressure, size, and location of disposal operations, impose limits on the types and amount of waste a facility may receive and the overall capacity of a waste disposal facility. States may add additional restrictions on the operations of a disposal facility when a permit is renewed or amended. As these regulations change, our permit requirements could become more stringent and may require material expenditures at our facilities or impose significant restraints or financial assurances on our operations.

In the course of our operations, some of our equipment may be exposed to naturally occurring radiation associated with oil and natural gas deposits, and this exposure may result in the generation of wastes containing Naturally Occurring Radioactive Materials, or NORM. NORM wastes exhibiting trace levels of naturally occurring radiation in excess of established state standards are subject to special handling and disposal requirements, and any storage vessels, piping, and work area affected by NORM may be subject to remediation or restoration requirements. It is possible that we may incur costs or liabilities associated with elevated levels of NORM.

Safe Drinking Water Act. Our underground injection operations are subject to the Safe Drinking Water Act, or SDWA, as well as analogous state laws and regulations. Under the SDWA, the EPA established the Underground Injection Control, or 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. 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 for property damages and personal injuries. In addition, storage of residual crude oil collected as part of the saltwater injection process prior to sale could impose liability on us in the event that the entity to which the oil was transferred fails to manage and, as necessary, dispose of residual crude oil in accordance with applicable environmental and occupational health and safety laws.

Our customers are subject to these same regulations. While these largely result in their needing our services, some waste regulations could have the opposite effect. For instance, some states, have considered laws mandating the recycling of flowback and produced water. If such laws are passed, our customers may divert some saltwater to recycling operations that may have otherwise been disposed of at our facilities.

Oil Pollution Act of 1990. The Oil Pollution Act of 1990, or OPA, as amended, establishes strict liability for owners and operators of facilities that are the site of a release of oil into regulated waters. The OPA also imposes ongoing requirements on owners or operators of facilities that handle certain quantities of oil, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. We handle oil at many of our facilities, and if a release of oil into the regulated waters occurred at one of our facilities, we could be liable for cleanup costs and damages under the OPA.

Water discharges. The federal Water Pollution Control Act, referred to as the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into regulated waters and impose requirements affecting our ability to conduct activities in regulated waters and wetlands. Pursuant to the Clean Water Act and analogous state laws, permits must be obtained to discharge pollutants into regulated waters, and permits or coverage under general permits must also be obtained to authorize discharges of storm water runoff from certain types of industrial facilities, including many of our facilities. 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 an appropriately issued permit. 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. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

We believe that compliance with existing permits and regulatory requirements under the Clean Water Act and state counterparts will not have a material adverse effect on our business. Future changes to permits or regulatory requirements under the Clean Water Act, however, could adversely affect our business.

Endangered species. The federal Endangered Species Act, or ESA, restricts activities that may affect endangered or threatened species or their habitats. Many states also have analogous laws designed to protect endangered or threatened species.

For example, the lesser-prairie chicken was listed as threatened in March 2014, although a district court recently vacated this decision. Additionally, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the Fish and Wildlife Service was required to make a determination on the listing of more than 250 species as endangered or threatened under the ESA by the end of the Fish and Wildlife Service's 2017 fiscal year. The Fish and Wildlife Service did not meet that deadline, but continues to consider whether to list additional species under the ESA.

Although current listings have not had a material impact on our operations, the designation of previously unidentified endangered or threatened species under the ESA or similar state laws could limit our ability to expand our operations and facilities or could force us to incur material additional costs. Moreover, listing such species under the ESA or

similar state laws could indirectly, but materially, affect our business by imposing constraints on our customers' operations, including the curtailment of new drilling or a refusal to allow a new pipeline to be constructed.

Air emissions. Some of our operations also result in emissions of regulated air pollutants. The Clean Air Act, or CAA, and analogous state laws require permits for and impose other restrictions on facilities that have the potential to emit substances into the atmosphere above certain specified quantities or in a manner that could adversely affect environmental quality. Failure to obtain a permit or to comply with permit requirements could result in the imposition of substantial administrative, civil, and even criminal penalties. We do not believe that any of our operations are subject to CAA permitting or regulatory requirements for major sources of air emissions, but some of our facilities could be subject to state "minor source" air permitting requirements and other state regulatory requirements for air emissions. Our Pipeline & Process Services segment has certain equipment requirements in various states.

Our customers' operations may be subject to existing and future CAA permitting and regulatory requirements that could have a material effect on their operations. The EPA recently approved and proposed new CAA rules requiring additional emissions controls and practices for oil and natural gas production wells, including wells that are the subject of hydraulic fracturing operations. The rules also establish new emission requirements for compressors, controllers, dehydrators, storage tanks, natural gas processing and certain other equipment used in the hydraulic fracturing process. These rules may increase the costs to our customers of developing and producing hydrocarbons, and as a result, may have an indirect and adverse effect on the amount of oilfield waste delivered to our facilities by our customers.

Climate change. The EPA has adopted regulations under existing provisions of the federal Clean Air Act that, for example, require certain large stationary sources to obtain Prevention of Significant Deterioration, or PSD, pre-construction permits and Title V operating permits for greenhouse gas (“GHG”) emissions. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas processing and fractionating facilities, which was expanded in October 2015 to include onshore petroleum and natural gas gathering and boosting activities and natural gas transmission pipelines. Additionally, the U.S. Congress has, in the past, considered adopting legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap-and-trade programs. Most of these cap-and-trade programs work by requiring major sources of emissions, such as electric power plants or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances that correspond to their annual emissions of GHGs. In addition, in December 2015, over 190 countries, including the United States, reached an agreement to reduce greenhouse gas emissions. The agreement entered into force in November 2016 after more than 70 countries, including the United States, ratified or otherwise consent to be bound by the agreement. However, in June 2017, President Trump announced that the United States plans to withdraw from the agreement and to seek negotiations either to reenter the agreement on different terms or a separately negotiated agreement. In August 2017, the U.S. Department of State officially informed the United Nations of the United States’ intent to withdraw from the agreement. The agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States’ adherence to the exit process and/or the terms on which the United States may re-enter the agreement or a separately negotiated agreement are unclear at this time. To the extent that the United States and other countries implement this agreement or impose other climate change regulations on the oil and natural gas industry, it could have an adverse effect on our business. The EPA and other federal and state agencies have also acted to address greenhouse gas emissions in other industries, most notably coal-fired power generation, and as a result could attempt in the future to impose additional regulations on the oil and natural gas industry.

Although it is not possible at this time to estimate how potential future laws or regulations addressing GHG emissions would impact our business, either directly or indirectly, any future federal or state laws or implementing regulations that may be adopted to address GHG emissions in areas where we operate could require us or our customers to incur increased operating costs. Regulation of GHGs could also result in a reduction in demand for and production of oil and natural gas, which would result in a decrease in demand for our services. We cannot predict with any certainty at this time how these possibilities may affect our operations, but effects could be materially adverse.

Hydraulic fracturing. We do not conduct hydraulic fracturing operations, but we do provide treatment and disposal services with respect to the fluids used and wastes generated by our customers in such operations, which are often necessary to drill and complete new wells and maintain existing wells. Hydraulic fracturing involves the injection of water, sand, or other proppants and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. Presently, hydraulic fracturing is regulated primarily at the state level, typically by state oil and natural gas commissions and similar agencies. Several states, including North Dakota, where we conduct our Water Services business, have either adopted or proposed laws and/or regulations to require oil and natural gas operators to disclose chemical ingredients and water volumes used to hydraulically fracture wells, in addition to more stringent well construction and monitoring requirements. The chemical ingredient information is generally available to the public via online databases including fracfocus.org, and this may bring more public scrutiny to hydraulic fracturing operations.

At the federal level, the SDWA regulates the underground injection of substances through the UIC program and generally exempts hydraulic fracturing from the definition of “underground injection.” The U.S. Congress has in recent legislative sessions considered legislation to amend the SDWA, including legislation that would repeal the exemption for hydraulic fracturing from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process.

Federal agencies have also asserted regulatory authority over certain aspects of the process within their jurisdiction. For example, the EPA issued an Advanced Notice of Proposed Rulemaking seeking comment on its intent to develop regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing, and proposed effluent limitations for the disposal of wastewater from unconventional resources to publicly owned treatment works. In addition, the U.S. Department of the Interior (“DOI”) published a rule that updates existing regulation of hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water. A U.S. District Court in Wyoming struck down this rule in June 2016; that ruling was overturned and the rule instated by the U.S. Court of Appeals for the Tenth Circuit in September 2017. The DOI formally rescinded the rule in December 2017.

The EPA conducted a study of the potential impacts of hydraulic fracturing activities on drinking water. The EPA released its final report in December 2016. The study concluded that under certain limited circumstances, hydraulic fracturing activities and related disposal and fluid management activities, could adversely affect drinking water supplies. This study and other studies that may be undertaken by the EPA or other governmental authorities, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise. If new federal, state or local laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities and make it more difficult or costly for our customers to perform fracturing. Any such regulations limiting or prohibiting hydraulic fracturing could reduce oil and natural gas exploration and production activities by our customers and, therefore, adversely affect our business. Such laws or regulations could also materially increase our costs of compliance and our cost of doing business by more strictly regulating how hydraulic fracturing wastes are handled or disposed.

Occupational Safety and Health Act. We are subject to the requirements of the Occupational Safety and Health Act, or OSHA and comparable state laws that regulate the protection of employee health and safety. OSHA’s hazard communications standard requires 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 and/or criminal fines, and changes in the way we operate our facilities that could have an adverse effect on our financial position.

Seismic activity. Several states have acted to address a growing concern that the underground injection of water into disposal wells has triggered seismic activity in certain areas. Any new seismic permitting requirements applicable to disposal wells impose more stringent permitting requirements and would be likely to result in added costs to comply or, perhaps, may require alternative methods of disposing of saltwater and other fluids, which could delay production schedules and also result in increased costs. Additional regulatory measures designed to minimize or avoid damage to geologic formations may be imposed to address such concerns.

Employees

The Partnership does not have any employees. All of the employees that conduct our business are employed by affiliates of our general partner, although we sometimes refer to these individuals in this report as our employees.

We are managed and operated by the directors and officers of our general partner. All of our executive management personnel are employees of CEM LLC or another affiliate of Holdings, and devote the portion of their time to managing our operations. As of December 31, 2018, 10 employees of CEM LLC provided services to us that are charged to us through the quarterly administrative fee that is specified in the omnibus agreement between the Partnership and Holdings.

As of December 31, 2018, affiliates of Holdings employed 117 people in our corporate office, who provide various services including management, human resources, information technology, safety, and accounting, among others. We directly reimburse Holdings and its affiliates for the cost of these employees.

Our Pipeline Inspection segment employs a number of inspectors that varies based on client needs (we generally only employ these inspectors when there is a specific client project to deploy them on). As of December 31, 2018, this segment employed approximately 1,453 inspectors. Of these inspectors, 5 were employed in Canada and the remainder were employed in the United States. We directly reimburse Holdings and its affiliates for the cost of these inspectors.

Our Pipeline & Process Services segment employed approximately 42 people at December 31, 2018. Most of the employees in the Pipeline & Process Services segment are full-time employees who are compensated regardless of whether or not they are deployed on a client project. We directly reimburse Holdings and its affiliates for the cost of these employees.

Our Water Services segment employed 10 people at December 31, 2018, all of whom work at our North Dakota facilities. We directly reimburse Holdings and its affiliates for the cost of these employees.

As of December 31, 2018, approximately 125 inspectors of our Pipeline Inspection segment are members of a union and are covered by collective bargaining arrangements. None of our other employees are covered by collective bargaining arrangements.

Insurance Matters

Our customers require that we maintain certain minimum levels of insurance and evaluate our insurance coverage as part of the initial and ongoing approval process they require to use our services to treat and dispose of their waste. We also carry a variety of insurance coverages for our operations as required by law. 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 have been subject to wide fluctuation, and changes in coverage could result in less coverage, increases in cost, or higher deductibles and retentions.

The saltwater disposal and the pipeline inspection and integrity businesses can be dangerous, involving unforeseen circumstances such as environmental damage from leaks, spills, or vehicle accidents. To address the hazards inherent in Water Services, our insurance coverage includes business, auto liability, commercial general liability, employer's liability, environmental and pollution, and other coverage. To address the hazards inherent in Pipeline Inspection and Pipeline & Process Services, insurance coverage includes employer's liability, auto liability, employee benefits liabilities, and contractor's pollution and other coverage. Coverage for environmental and pollution-related losses is subject to significant limitations and are commonly provided for exclusion on such policies. We do not carry business interruption insurance, given its cost and its coverage limitations.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (the “Exchange Act”) are made available free of charge on our website at www.cypressenergy.com as soon as reasonably practicable after these reports have been electronically filed with, or furnished to, the SEC. Unitholders may request a printed copy of these reports free of charge by contacting Investor Relations at Cypress Energy Partners, L.P., 5727 S. Lewis Ave., Suite 300, Tulsa, OK 74105 or by e-mailing ir@cypressenergy.com. These documents are also available on the SEC’s website at www.sec.gov, or a unitholder may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. No information from either the SEC’s website or our website is incorporated herein by reference.

ITEM 1A. RISK FACTORS

Unitholders should consider carefully the following risk factors together with all of the other information included in this Annual Report on Form 10-K and our other reports filed with the SEC before investing in our common units. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our common units could decline and a unitholder could lose all or part of their investment.

Risks Related to Our Business

We may not be able to pay quarterly distributions to holders of our common units because we may not have sufficient cash from operations due to our establishment of cash reserves, payment of fees and expenses, and cash reimbursement to our General Partner and its affiliates.

We may not have sufficient available cash from operating surplus each quarter to enable us to pay any distributions to our common unitholders. The holders of our Series A preferred units representing limited partner interests in the Partnership (“Series A Preferred Units”) (to the extent of a distribution equal to 9.5% per annum plus accrued and unpaid distributions) are entitled to receive quarterly cash distributions prior to distributions to holders of our common units.

In order to pay a distribution at our current rate of \$0.21 per common unit per quarter, or \$0.84 per common unit on an annualized basis, we will require available cash of approximately \$2.5 million per quarter, or \$10.0 million per year, based on the number of outstanding common units as of March 11, 2019. We may not have sufficient available cash from operating surplus each quarter to enable us to pay the common unit distribution. The amount of cash we can distribute to our unitholders principally depends upon the amount of cash we generate from our operations, which fluctuates from quarter to quarter based on, among other things:

the fees we charge, and the margins we realize, from Pipeline Inspection, Pipeline & Process Services and Water Services;

the number and types of projects conducted by Pipeline Inspection and Pipeline & Process Services and the volume of saltwater handled in Water Services;

the amount of residual oil we are able to separate and sell from the saltwater we receive that can be impacted by the quality and price of the oil;

the cost of achieving organic growth in current and new markets;

our ability to make profitable acquisitions of pipeline inspection and integrity companies, other saltwater disposal facilities, and other types of businesses;

the level of competition from other companies;

governmental regulations, including changes in governmental regulations, in our industry;

prevailing economic and market conditions, including low or volatile commodity prices and their effect on our customers; and

weather and natural disasters, lightning, seismic activity, vandalism and acts of terror.

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

restrictions contained in our debt agreements;

our debt service requirements, interest rates, and other liabilities;

the level of capital expenditures we make;

the cost of acquisitions;

the level of our operating costs and expenses and the performance of our various facilities, inspectors and staff;

fluctuations in our working capital needs;

our ability to borrow funds and access capital markets;

the amount of cash reserves established by our general partner; and

other business risks affecting our cash levels.

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

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

The level of activity in the oil and natural gas exploration and production industry in the U.S. has been volatile. According to a published oil and gas drilling rig count, the U.S. weekly aggregate rig count reached an all-time high of 4,530 rigs in December 1981 and a post-1942 low rig count of 404 rigs in May 2016. The prices of crude oil and related products dropped substantially in the fourth quarter of 2014, have stayed low, and have been negatively affected by a combination of factors, including weakening demand, increased worldwide production, the decision by the Organization of Petroleum Exporting Countries to keep production levels unchanged and a strengthening in the U.S. dollar relative to most other currencies. If crude oil prices do not rise, or take longer to recover than anticipated, E&P companies, pipeline owners and operators and public utility or local distribution companies in the regions we conduct our business may reduce capital spending maintaining their pipelines or oil and natural gas production. Water

Services constitutes approximately 4%, 3%, and 3% of our revenue for the years ended December 31, 2018, 2017, and 2016, respectively. The Bakken region of North Dakota generally requires higher oil prices than certain other regions in order to generate suitable economic returns for E&P companies. Therefore, a continued decrease in drilling activity or hydraulic fracking could have an adverse effect on our financial position, results of operations, demand for services, cash flows or our ability to make cash distributions to our unitholders or required payments on our outstanding debt.

Our customers' willingness to engage in drilling and production of 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 oil and natural gas;

the level of prices, and market expectations with respect to future prices of oil and natural gas;

the cost of exploring for, developing, producing, and delivering oil and natural gas;

the cost of fracturing services;

the market's expected rate of decline of current oil and natural gas production;

the rate and frequency at which new oil and natural gas reserves are discovered;

available pipeline and other transportation capacity;

lead times associated with acquiring equipment and products and availability of personnel;

weather conditions, including hurricanes, tornadoes, earthquakes, wildfires, drought or man-made disasters that can affect oil and natural gas operations over a wide area, as well as local weather conditions such as unusually cold winters in the Bakken Shale region of the Williston Basin in North Dakota that can have a significant impact on drilling activity in that region;

domestic and worldwide economic conditions;

contractions in the credit market;

political instability in certain 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 or other parts of the world;

governmental regulations, including income tax laws or government incentive programs relating to the oil and natural gas industry and the policies of governments regarding the exploration for and production and development of oil and natural gas reserves;

the level of oil production by non-OPEC countries and the available excess production capacity contained in OPEC member countries;

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;

access to necessary labor and services;

the access to and cost of debt and equity capital for oil and natural gas producers;

merger and divestiture activity among oil and natural gas producers; and

the impact of changing regulations and environmental and safety rules and policies.

The working capital needs of the Pipeline Inspection segment are substantial, and will continue to be substantial. This will reduce our borrowing capacity for other purposes and reduce our cash available for distribution.

We pay the majority of our inspectors in the Pipeline Inspection segment on a weekly basis, but typically receive payment from our customers 45 to 90 days after the inspectors' services have been performed. We intend to make borrowings under our credit facility to fund the working capital needs of Pipeline Inspection, and these borrowings will reduce the amount of credit we may use for other needs, such as working capital for our water disposal business, acquisitions and growth projects. Borrowings also increase our aggregate interest expense, which indirectly reduces cash available for distribution to our unitholders. Any cash generated from operations used to fund working capital needs will also reduce cash available for distribution to our unitholders. Additionally, if our pipeline inspection and integrity services customers delay in paying us, our working capital will decrease such that we would be required to make further borrowings under our revolving credit facility; these delays in our customers' payments would also impact our ability to pay our quarterly distributions.

The bankruptcy of PG&E Corporation could adversely affect the Company's results of operations, financial condition and cash flows.

On January 29, 2019, PG&E Corporation and its wholly-owned subsidiary Pacific Gas and Electric Company (collectively, "PG&E") filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Northern District of California (the "PG&E Bankruptcy"). PG&E is a significant customer that accounted for \$43.4 million of the revenue and \$6.4 million of the gross margin of our Pipeline Inspection segment during the year ended December 31, 2018. As of December 31, 2018, the assets on our Consolidated Balance Sheet included

\$10.3 million of accounts receivable from PG&E. We collected \$1.0 million of this balance in January 2019 prior to PG&E's bankruptcy filing. We generated \$2.8 million of revenue from PG&E during the period from January 1, 2019 through January 28, 2019, bringing the total accounts receivable from PG&E to \$12.1 million as of the date of the bankruptcy filing.

We have not recorded an allowance against the accounts receivable from PG&E at December 31, 2018, as we do not believe it is probable that we will ultimately be unable to collect the full balance of the pre-petition receivables. However, any delay in collecting these receivables may require us to maintain a larger outstanding debt balance on the revolving credit facility than otherwise would have been required, which would leave us with less flexibility to pursue growth opportunities than we otherwise would have enjoyed. If PG&E does not have the financial means or refuses to pay the amounts owed to the Partnership, and if the Partnership cannot recover the amounts owed through other means, the Partnership may be required to write-off all, or a portion of, any outstanding accounts receivable. Any such results would adversely affect the Partnership's financial results.

The Partnership continues to assess the potential future impacts of the PG&E Bankruptcy on the Partnership's operations. The realization of any of the above risks could significantly and adversely affect the Partnership's ability to meet its financial expectations, its financial condition, results of operations, and cash flows, its ability to make distributions to its unitholders, the market price of its common stock, and its ability to satisfy its debt service obligations.

Our ability to grow in the future is dependent on our ability to access external growth capital.

We will distribute substantially all of our available cash after expenses and prudent operating reserves to our unitholders. We expect that we will rely primarily upon external financing sources, including borrowings under our credit facilities and the issuance of debt and equity securities, to fund growth 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, Holdings is under no obligation to fund our growth. To the extent we issue additional units in connection with the financing of other growth 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.

In the ordinary course of our business, we may become subject to lawsuits, indemnity, or other claims, which could materially and adversely affect our business, financial condition, results of operations, profitability, cash flows, and growth prospects.

From time to time, we are subject to various claims, lawsuits and other legal proceedings brought or threatened against us in the ordinary course of our business. These actions and proceedings may seek, among other things, compensation for alleged personal injury, workers' compensation, employment discrimination and other employment-related damages, breach of contract, property damage, environmental liabilities, multiemployer pension plan withdrawal liabilities, punitive damages and civil penalties or other losses, liquidated damages, consequential damages, or injunctive or declaratory relief. We may also be subject to litigation involving allegations of violations of the Fair Labor Standards Act and state wage and hour laws. In addition, we generally indemnify our customers for claims related to the services we provide and actions we take under our contracts, and, in some instances, we may be allocated risk through our contract terms for actions by our customers or other third parties.

Our existing and future debt levels may limit our flexibility to obtain financing and to pursue other business opportunities.

As of December 31, 2018, we had \$76.1 million of indebtedness outstanding under our Credit Agreement. In May 2018, we entered into a new Credit Agreement for a total of \$90.0 million, with an accordion feature of \$20.0 million (\$110.0 million total). We may be able to incur additional debt, subject to limitations in our Credit Agreement. Our degree of leverage could have important consequences to us, including the following:

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

our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flow 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 refinance and 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 our current or future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all.

On May 29, 2018 (the “Closing Date”), we entered into a Series A Preferred Unit Purchase Agreement (the “Preferred Unit Purchase Agreement”) with an entity controlled by Charles C. Stephenson, Jr. (the “Purchaser”), an affiliate of our General Partner, where we issued and sold in a private placement 5,769,231 Series A Preferred Units representing limited partner interests in the Partnership (the “Preferred Units”) to the Purchaser for a cash purchase price of \$7.54 per Preferred Unit, resulting in gross proceeds to the Partnership of \$43.5 million.

The Purchaser is entitled to receive quarterly distributions that represent an annual return of 9.5% on the Preferred Units. Of this 9.5% annual return, we will be required to pay at least 2.5% in cash and will have the option to pay the remaining 7.0% in kind (in the form of issuing additional preferred units) for the first twelve quarters after the Closing Date. Distributions we pay on preferred units reduce the cash available for other purposes. Our preferred units rank senior to our common units, and we must pay distributions on our preferred units (including any arrearages) before paying distributions on our common units. In addition, the preferred units rank senior to the common units with respect to rights upon liquidation.

We do not enter into long-term contracts with our customers, which subjects us to renewal or termination risks.

We do not typically enter into long-term contracts with our customers. While we frequently operate under master services agreements with customers that set forth the terms on which we will provide services, customers operating under these agreements typically have the ability to terminate their relationship with us at any time at their sole discretion by choosing to not use us to provide pipeline inspection and integrity management services or by ceasing to deliver saltwater to our saltwater disposal facilities. Therefore, it is possible that our customers may decide not to use our inspection and integrity services or dispose of their saltwater through us. The failure of customers to continue to use our services could adversely affect our operations, financial condition, cash flows and ability to make cash distribution to our unitholders.

We depend on a limited number of customers for a substantial portion of our revenues. The loss of, or a material nonpayment by, any of our key customers could adversely affect our results of operations, financial condition and ability to make cash distributions to our unitholders.

Our ten largest customers generated approximately 67%, 68% and 80% of our consolidated revenue for the years ended December 31, 2018, 2017, and 2016, respectively. Two customers accounted for more than 10% of revenues for the year ended December 31, 2018, and three customers accounted for more than 10% of revenues for each of the years ended December 31, 2017 and 2016; Pacific Gas and Electric Company and Plains All America Pipeline in 2018, Enterprise Product Partners, Pacific Gas and Electric Company and Plains All America Pipeline in 2017 and Enbridge Energy Partners, Pacific Gas and Electric Company and Plains All America Pipeline in 2016. These are customers of our Pipeline Inspection segment. The loss of all, or even a portion of the revenues from these customers, as a result of competition, market conditions or otherwise, could have a material adverse effect on our business, results of operations, financial condition, and cash flows.

PG&E Corporation and its wholly-owned subsidiary Pacific Gas and Electric Company (collectively, “PG&E”) filed for bankruptcy protection on January 29, 2019. We continue to provide services to PG&E and we believe that we will be paid in the normal course for services provided after the bankruptcy filing. However, due to uncertainties associated with the bankruptcy process, we cannot make assurances regarding the ultimate collection of our pre-petition receivables, the timing of any such collections, and our ability to retain PG&E as a customer.

Our business is dependent upon the willingness of our customers to outsource their pipeline inspection and integrity service activities and waste management activities.

Our business is largely dependent on the willingness of customers to outsource their pipeline inspection and integrity service activities and their water and environmental treatment services. Some pipeline owners and operators currently inspect and perform integrity activities on their own pipeline systems using the same techniques and technologies that

we use, as well as others that we currently do not employ. In addition, many oil and natural gas producing companies own and operate waste treatment, recovery, and saltwater disposal facilities that provide services that we could otherwise provide to them, and some producers recycle saltwater on-site that we could otherwise dispose for them. Most oilfield operators, including many of our customers, have numerous abandoned wells that could be licensed to dispose of internally generated waste and third-party waste, which, if our customers did license these abandoned wells, could result in competition for us. Additionally, technologies may be developed that could allow our customers to recycle saltwater and to recover oil through oilfield waste processing, which would make our services unnecessary. Our current customers could decide to inspect and perform integrity activities on their own pipeline systems or process and dispose of their waste internally, either of which could have a material adverse effect on our financial position, results of operations, cash flows, and our ability to make cash distributions to our unitholders.

Our markets are highly competitive, and increased competition could adversely impact our financial position, our results of operations, demand for our services, our cash flows, or our ability to make required payments on outstanding debt.

We have many competitors in our primary markets in the Pipeline Inspection, Pipeline & Process Services and Water Services segments. Some of our customers also compete with us in the treatment and disposal sector by offering similar such services to other oil and natural gas companies. Our customers regularly evaluate the best combination of value and price from competing alternatives and new technologies and 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 aggressively control our costs 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 services or new technologies that have pricing, location, lower cost of capital or other advantages over the services we provide.

The credit risks of our concentrated customer base could indirectly result in losses to us.

Many of our customers are oil and natural gas companies that have or may face liquidity constraints in light of the current commodity price environment. This concentration of our customers in the energy industry may impact our overall exposure to credit risk, since our customers may be similarly affected by prolonged changes in economic and industry conditions. If a significant number of our customers experience a prolonged business decline or disruptions, we may incur increased exposure to credit risk and bad debts.

PG&E Corporation and its wholly-owned subsidiary Pacific Gas and Electric Company (collectively, “PG&E”) filed for bankruptcy protection on January 29, 2019. We continue to provide services to PG&E and we believe that we will be paid in the normal course for services provided after the bankruptcy filing. However, due to uncertainties associated with the bankruptcy process, we cannot make assurances regarding the ultimate collection of our pre-petition receivables or the timing of any such collections.

A failure by our employees to follow applicable procedures and guidelines or on-site accidents could have a material adverse effect on our business.

We require our employees to comply with various internal procedures and guidelines, including an environmental management program and worker health and safety guidelines. The failure by our employees to comply with our internal environmental, health and safety guidelines could result in personal injuries, property damage or non-compliance with applicable governmental laws and regulations, which may lead to fines, remediation obligations or third-party claims. Any such fines, remediation obligations, third-party claims or losses could have a material adverse effect on our financial position, results of operations, and cash flows. In addition, on-site accidents can result in injury or death to our or other contractors' employees or damage to our or other contractors' equipment and facilities and damage to other people, truck drivers, area residents, and property. Any fines or third-party claims resulting from any such on-site accidents could have a material adverse effect on our business.

In addition, while an inspector is performing pipeline inspection or integrity services for us, the inspector is considered our employee and is eligible for workers' compensation claims if the inspector is injured or killed while working for us. As the inspectors generally travel to and from projects in their own vehicles, we may be responsible for workers compensation claims or third-party claims arising out of vehicle accidents, which could negatively affect our results of operations.

Unsatisfactory safety performance may negatively affect our customer relationships, workers compensation rates and, to the extent we fail to retain existing customers or attract new customers, adversely impact our revenues.

Our ability to retain existing customers and attract new business is dependent on many factors, including our ability to demonstrate that we can reliably and safely operate our business and stay current on constantly changing rules, regulations, training, and laws. Existing and potential customers consider the safety record of their service providers to be of high importance in their decision to engage third-party servicers. If one or more accidents were to occur at one of our operating sites, or pipelines or gathering systems we inspect, the affected customer may seek to terminate or cancel its use of our facilities or services and may be less likely to continue to use our services, which could cause us to lose substantial revenues. Further, our ability to attract new customers may be impaired if they elect not to purchase our third-party services because they view our safety record as unacceptable. In addition, it is possible that we will experience numerous or particularly severe accidents in the future, causing our safety record to deteriorate. This may be more likely as we continue to grow, if we experience high employee turnover or labor shortage, or add inexperienced personnel. In addition, we could be subject to liability for damages as a result of such accidents and could incur penalties or fines for violations of applicable safety laws and regulations.

Disruptions in the transportation services of trucking companies transporting saltwater could adversely affect our results of operations and cash available for distribution to our unitholders.

We primarily depend on third party trucking companies to transport saltwater to our saltwater disposal facilities. In recent years, certain states, including North Dakota, and certain counties, have increased enforcement of weight limits they impose on saltwater disposal trucks. Also, as a result of regulations issued in March 2014, all waste haulers transporting produced water in North Dakota must possess a valid permit for transporting solid waste from the North Dakota Department of Health. It is possible that the states, counties and cities in which the Water Services segment conducts its operations may modify their laws to further reduce truck weight limits, or impose curfews or other restrictions on the use of roadways. Such legislation and enforcement efforts could result in delays and increased costs in transporting saltwater to our saltwater disposal facilities, which may either increase our operating costs or reduce the amount of saltwater transported to our saltwater disposal facilities. This could decrease our operating margins and thereby affect our results of operations and cash available for distribution.

A significant increase in fuel or insurance prices may adversely affect the transportation costs of our trucking company customers, which could result in a decrease in the rates for our saltwater and environmental services they would be willing to pay.

A significant increase in fuel prices will result in increased transportation costs to our trucking customers. The price and supply of fuel is unpredictable and fluctuates based on events such as geopolitical developments, supply and demand for oil and natural gas, actions by oil and natural gas producers, war and unrest in oil producing countries and regions, regional production patterns and weather concerns. A significant increase in fuel prices could result in our trucking company customers becoming unwilling to pay the resulting increase in disposal fees, which would reduce our revenues and impact our ability to make distributions to our unitholders. A significant increase in insurance prices or decrease in availability of coverage also would result in increased transportation costs to our customers.

We sell residual oil that we recover during our saltwater treatment process. Volumes of residual oil recovered during the saltwater treatment process can vary. Any significant reduction in residual oil content in the water we treat, or the price we achieve for residual oil sales, will affect our recovery of residual oil and, indirectly, our profitability.

Approximately 5%, 7%, and 6% of our revenue for the years ended December 31, 2018, 2017, and 2016, respectively, in the Water Services segment was derived from sales of residual oil recovered during the saltwater treatment process. Our ability to recover sufficient volumes of residual oil is dependent upon the residual oil content in the saltwater we treat, which is, among other things, a function of water type, chemistry, source, and temperature. Generally, where outside temperatures are lower, there is less residual oil content and separation is more difficult. Thus, our residual oil recovery during the winter season is lower than our recovery during the summer season in North Dakota. Additionally, residual oil content will decrease if, among other things, producers recover higher levels of residual oil in saltwater prior to delivering such saltwater to us for treatment. Also, the revenues we derive from sales of residual oil are subjected to fluctuations in the price of oil. Any reduction in residual crude oil content in the saltwater we treat or the prices we realize on our sales of residual oil could materially and adversely affect our profitability.

We are vulnerable to the potential difficulties, expenses and uncertainties associated with rapid growth and expansion.

We grew rapidly since our inception in 2012, prior to the industry downturn, primarily through acquisitions. We believe that our future success depends on our and our management's ability to manage growth, including increased demands and responsibilities. The following factors could present difficulties to us:

- organizational challenges common to large, expansive operations;
- administrative burdens;
- employee insurance;
- limitations with systems and technology;
- safety and training;
- ability to recruit, train, and retain personnel and managers;
- ability to obtain permits for expanded operations;
- access to debt and equity capital on attractive terms; and
- long lead times associated with acquiring equipment and building any new facilities.

Our operating results could be adversely affected if we do not successfully manage any of these potential difficulties.

Our utilization of existing capacity, expansion of existing saltwater disposal facilities, and construction or purchase of new saltwater disposal facilities may not result in revenue increases and will be subject to regulatory, environmental, political, legal, and economic risks, which could adversely affect our operations and financial condition.

A portion of our strategy to grow and increase distributions to unitholders is dependent on our ability to utilize available capacity at our existing facilities, expand existing saltwater disposal facilities and construct or purchase new saltwater disposal facilities. The construction of a new saltwater disposal facility or the extension, renovation or expansion of an existing saltwater disposal facility, such as by connecting such saltwater disposal facility to existing or newly constructed pipeline systems, involves numerous business, competitive, regulatory, environmental, political, and legal uncertainties, most of which are beyond our control. If we undertake these projects, they may not be completed on schedule, at all, or at the budgeted cost. Furthermore, we will not receive any material increases in revenues until after completion of the project, although we will have to pay financing and construction costs during the construction period. As a result, new saltwater disposal facilities may not be able to attract enough demand for water and environmental services to achieve our expected investment return, which could materially adversely affect our results of operations and financial condition and our ability in the future to make distributions to our unitholders.

Our ability to acquire assets from Holdings or third parties is subject to risks and uncertainty. If we are unable to make acquisitions on economically acceptable terms, our future growth would be limited, and any acquisitions we may make may reduce, rather than increase, our cash flows and ability to make distributions to unitholders. Furthermore, we may not realize the benefits from or successfully integrate any acquisitions.

A portion of our strategy to grow our business and increase distributions to unitholders is dependent on our ability to make acquisitions that result in an increase in cash we generate on a per unit basis. The acquisition component of our strategy is based, in large part, both on our expectation of continuing consolidation in the industries in which we operate and our ability to acquire interests in additional assets from Holdings (discussed directly below).

Holdings is seeking acquisitions of other types of businesses that may be suitable to our operations in the future. We may have the opportunity to make acquisitions directly from Holdings and its affiliates. The consummation and timing of any future acquisitions of these assets will depend upon, among other things, Holdings' and its affiliates' willingness to offer these assets for sale, our ability to negotiate acceptable purchase agreements and commercial agreements with respect to the assets and our ability to obtain financing on acceptable terms. We can offer no assurance that we will be able to successfully consummate any future acquisitions with Holdings and its affiliates, and Holdings and its affiliates are under no obligation to accept any offer that we may choose to make. In addition, certain of these assets may require substantial capital expenditures in order to maintain compliance with applicable regulatory requirements or otherwise make them suitable for our commercial needs. For these or a variety of other reasons, we may decide not to acquire these assets from Holdings and its affiliates if, and when, Holdings and its affiliates offers such assets for sale, and our decision will not be subject to unitholder approval.

Additionally, we may not be able to make accretive acquisitions from third parties if we are:

unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts;

unable to obtain financing for these acquisitions on economically acceptable terms;

outbid by competitors; or

for any other reason.

If we are unable to make acquisitions from Holdings and its affiliates or third parties, our future growth and ability to increase distributions will be limited. Furthermore, even if we do consummate acquisitions that we believe will be accretive, they may in fact result in a decrease in cash flow.

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

mistaken assumptions about disposal capacity, number and quality of inspectors, revenues and costs, cash flows, capital expenditures, and synergies;

the assumption of unknown liabilities;

limitations on rights to indemnity from the seller;

mistaken assumptions about the overall costs of equity or debt;

the diversion of management's attention from other business concerns;

integrating business operations or unforeseen regulatory issues;

unforeseen new regulations;

unforeseen difficulties operating in new geographic areas; and

customer or key personnel losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and unitholders will not have the opportunity to evaluate the economic, financial, and other relevant information that we will consider in determining the application of these funds and other resources.

We conduct a portion of our operations through entities that we partially own, which subjects us to additional risks that could have a material adverse effect on our financial condition and results of operations.

We own a 51.0% interest in Brown, a 25% interest in Alati Arnegard, LLC, and a 49.0% interest in CF Inspection. We may also enter into other arrangements with third parties in the future. Other third parties in future arrangements may have obligations that are important to the success of the arrangement, such as the obligation to pay their share of capital and other costs of these partially owned entities. The performance of these third-party obligations, including the ability of our current partners to satisfy their respective obligations, is outside our control. If these parties do not satisfy their obligations under the arrangements, our business may be adversely affected.

Our joint venture arrangements may involve risks not otherwise present without a partner, including, for example:

our partner shares certain blocking rights over transactions;

our partner may take actions contrary to our instructions or requests or contrary to our policies or objectives;

although we may control these joint ventures, we may have contractual duties to the joint ventures' respective other owners, which may conflict with our interests and the interests of our unitholders; and

disputes between us and other partners may result in delays, litigation or operational impasses.

The risks described above or any failure to continue joint ventures or to resolve disagreements with our third-party partners could adversely affect our ability to transact the business that is the subject of such business, which would, in turn, negatively affect our financial condition, results of operations, and ability to distribute cash to our unitholders.

Restrictions in our Credit Agreement could adversely affect our business, financial condition, results of operations, ability to make cash distributions to our unitholders and the value of our units.

In May 2018, we entered into a new Credit Agreement for \$90.0 million, with a \$20.0 million accordion feature (\$110.0 million total). Our Credit Agreement limits our ability to, among other things:

- incur or guarantee additional debt;
- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- alter our line of business;
- enter into certain types of transactions with affiliates;
 - merge or consolidate with another company; and
- transfer, sell or otherwise dispose of assets.

The Credit Agreement also contains certain covenants requiring us to maintain certain financial ratios. 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 be able to meet these ratios and tests.

The provisions of our Credit Agreement 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. For example, our funds available for operations, future business opportunities and cash distributions to unitholders may be reduced by that portion of our cash flow required to make interest payments on our debt. Our ability to service our debt may depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service any future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We cannot assure unitholders that we would be able to take any of these actions, that these actions would be successful and permit us to meet our scheduled debt service obligations or satisfy our capital requirements, or that these actions would be permitted under the terms of our Credit

Agreement, or future debt agreements. Our debt documents restrict our ability to dispose of assets and use the proceeds from the disposition. We may not be able to consummate those dispositions or to obtain the proceeds which we could realize from them and these proceeds may not be adequate to meet any debt service obligations then due. In addition, a failure to comply with the provisions of our credit facilities could result in a default or an event of default that could enable its 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 debt is accelerated, defaults under its other debt instruments, if any, may be triggered, and our assets may be insufficient to repay such debt in full, and the holders of our units could experience a partial or total loss of their investment in us. Please read “*Item 7 – Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources*” for additional information about our credit facilities.

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

We own and operate saltwater disposal facilities in North Dakota, which are subject to regulatory programs for addressing the handling, treatment, recycling and disposal of saltwater. We are also required to comply with federal laws and regulations governing our operations. These environmental laws and regulations require that we, among other things, obtain permits and authorizations prior to our developing and operating waste treatment and storage facilities and in connection with our disposing and transporting certain types of waste. Regulatory agencies strictly monitor waste handling and disposal practices at all of 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 oilfield water and environmental services to our 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 waste we can 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, nongovernmental 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. It is not uncommon for local property owners or, in some cases, oil and natural gas producers, to oppose saltwater disposal permits. Any such limitations or requirements could limit the water and environmental services we provide to our customers, or make such services more expensive to provide, which could have a material adverse effect on our financial position, results of operations, cash flows, and our ability to make cash distributions to our unitholders.

Our customers' delays in obtaining permits for their operations could impair our business.

In most states, our customers are required to obtain permits from one or more governmental agencies in order to perform drilling and completion activities and to operate pipeline and gathering systems. Such permits are typically issued by state agencies, but federal and local governmental permits may also be required. The requirements for such permits vary depending on the location where such drilling and completion, and pipeline and gathering activities will be conducted. 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. Recently, moratoriums on the issuance of permits for certain types of drilling and completion activities have been imposed in some areas, such as New York. Some of our customers' drilling and completion activities may also 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 U.S. may be interrupted or suspended for varying lengths of time, causing a loss of revenue to us and 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 saltwater disposal facilities and we may be required to provide an increased level of financial assurance to regulatory agencies to ensure the appropriate closure activities occur for a saltwater disposal facility.

Obtaining a permit to own or operate a saltwater disposal facility generally requires us to establish performance bonds, letters of credit or other forms of financial assurance to address clean up and closure obligations at our saltwater disposal facilities. In particular, the North Dakota regulatory agencies require us to post letters of credit in connection with the operation of our saltwater disposal facilities. As we acquire additional saltwater disposal facilities or expand our existing saltwater disposal facilities, these obligations will increase. Additionally, in the future, regulatory agencies may require us to increase the amount of our closure bonds at existing saltwater disposal facilities. We have accrued approximately \$0.1 million on our Consolidated Balance Sheet related to our contemplated future closure obligations of our saltwater disposal facilities as of December 31, 2018. This amount was calculated by estimating the total amount of closure obligations and the dates at which such closures might occur and discounting this total estimated cost to calculate a present value. However, actual costs could exceed our current expectations, as a result of, among other things, federal, state or local government regulatory action, increased costs our service providers charge who assist in closing saltwater disposal facilities, and additional environmental remediation requirements. Increased regulatory requirements regarding our existing or future saltwater disposal facilities, including the requirement to pay increased closure and post-closure costs or to establish increased financial assurance for such activities could substantially increase our operating costs and cause our available cash that we have to distribute to our unitholders to decline.

Changes in laws or government regulations regarding hydraulic fracturing could increase our customers' costs of doing business, limit the areas in which our customers can operate and reduce oil and natural gas production by our customers, which could adversely impact our business.

We do not conduct hydraulic fracturing operations, but we do provide treatment and disposal services with respect to the fluids used and wastes generated by our customers in such operations, which are often necessary to drill and complete new wells and maintain existing wells. Hydraulic fracturing involves the injection of water, sand or other proppants and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate oil and gas production. Presently, hydraulic fracturing is regulated primarily at the state level, typically by state oil and natural gas commissions and similar agencies. Several states, including North Dakota, where we conduct our water and environmental services business, have either adopted or proposed laws and/or regulations to require oil and natural gas operators to disclose chemical ingredients and water volumes such operators use to hydraulically fracture wells. These states also impose stringent well construction and monitoring requirements. The chemical ingredient information we provide to these states is generally available to the public via online databases including fracfocus.org. Making this information publicly available may bring more scrutiny to hydraulic fracturing operations.

At the federal level, the SDWA regulates the underground injection of substances through the UIC program and generally exempts hydraulic fracturing from the definition of “underground injection.” The U.S. Congress has in recent legislative sessions considered legislation to amend the SDWA. Such legislation would repeal the exemption for hydraulic fracturing from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process.

Federal agencies have also asserted regulatory authority over certain aspects of the process within their respective jurisdictions. For example, the EPA issued an Advanced Notice of Proposed Rulemaking seeking comment on its intent to develop regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing, and proposed effluent limitations for the disposal of wastewater from unconventional resources to publicly owned treatment works.

The EPA conducted a study of the potential impacts of hydraulic fracturing activities on drinking water. The EPA released its final report in December 2016. The study concluded that under certain limited circumstances, hydraulic fracturing activities and related disposal and fluid management activities, could adversely affect drinking water supplies. As part of this study, the EPA requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. This study and other studies that may be undertaken by the EPA or other governmental authorities, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise. If new federal, state or local laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities and make it more difficult or costly for our customers to perform fracturing. Any such regulations limiting or prohibiting hydraulic fracturing could reduce oil and natural gas exploration and production activities by our customers and, therefore, adversely affect our business. Such laws or regulations could also materially increase our costs of compliance and doing business by more strictly regulating how hydraulic fracturing wastes are handled or

disposed.

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 oil and natural gas producers' water recycling efforts which would decrease the volume of saltwater delivered to our saltwater disposal facilities and correspondingly decrease our revenues attributed to saltwater delivery services.

Water is an essential component of oil and natural gas production during the drilling, and in particular, hydraulic fracturing, process. However, the availability of suitable water supplies may be limited by natural occurrences, such as prolonged droughts. As a result, some local water districts have begun restricting the use of water for hydraulic fracturing in an effort to protect local water supplies. For example, in response to continuing drought conditions in 2015, 2014, and 2013, the Texas Legislature considered a number of bills that would have mandated recycling of flowback and produced water and/or prohibited recyclable water from being disposed of in wells. If oil and natural gas producers are unable to obtain water to use in their operations from local sources, they may be incentivized to recycle and reuse saltwater instead of delivering such saltwater to our saltwater disposal facilities. Similarly, mandatory recycling programs could reduce the amount of materials sent to us for treatment and disposal. Any such limits or mandates could adversely affect our business and results of operations.

Increased attention to seismic activity associated with hydraulic fracturing and underground disposal could result in additional regulations and adversely impact demand for our services.

There exists a growing concern among certain experts in the oil and gas industry that the underground injection of produced water into disposal wells has triggered seismic activity in certain areas. Some states have promulgated rules or guidance in response to these concerns. For example, in Texas, the Texas Railroad Commission (“TRC”) published a final rule in October 2014 governing permitting or re-permitting of disposal wells that will require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections, and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the injected fluids are confined to the disposal zone, or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend, or terminate the permit application or existing operating permit for that well. New seismic permitting requirements applicable to disposal wells impose more stringent permitting requirements and would be likely to result in added costs to comply, or perhaps, may require alternative methods of disposing of saltwater and other fluids, which could delay production schedules and also result in increased costs. Additional regulatory measures designed to minimize or avoid damage to geologic formations may be imposed to address such concerns.

We and our customers may incur significant liability under, or costs and expenditures to comply with, environmental regulations, which are complex and subject to frequent change.

Our and our customer’s operations are subject to stringent federal, state, provincial and local laws and regulations relating to, among other things, protection of natural resources, wetlands, endangered species, the environment, waste management, waste disposal, and transportation of waste and other materials. These laws and regulations may impose numerous obligations that are applicable to our and our customer’s 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, and the imposition of substantial liabilities and remedial obligations for pollution or contamination resulting from our and our customer’s operations.

Compliance with this complex array of laws and regulations is difficult and may require us to make significant expenditures. A breach of such requirements may result in suspension or revocation of necessary licenses or authorizations, civil liability for, among other things, pollution damage and the imposition of material fines.

Our operations also pose risks of environmental liability due to leakage, migration, releases or spills from our operations to surface or subsurface soils, surface water, or groundwater. Some environmental laws and regulations impose strict, joint and several liabilities in connection with releases of regulated substances into the environment. Therefore, in some situations we could be exposed to liability as a result of our conduct that was lawful at the time it occurred or the conduct of, or conditions caused by, third parties.

Laws protecting the environment generally have become more stringent over time. We expect this trend to continue, which could lead to material increases in our costs for future environmental compliance and remediation, and could adversely affect our operations by restricting the way in which we treat and dispose of exploration and production, or E&P, waste, or our ability to expand our business.

In particular, the RCRA, which governs the disposal of solid and hazardous waste, currently exempts certain E&P wastes from classification as hazardous wastes. In recent years, proposals have been made to rescind this exemption from RCRA. For example, in May 2016, a nonprofit environmental group filed suit in the federal district court for the District of Columbia, seeking a declaratory judgment directing the EPA to review and reconsider the RCRA E&P waste exemption. EPA and the environmental group entered into an agreement that was formalized in a consent decree issued by the US District court for the District of Columbia in December 2016. Under the decree, the EPA is required to propose a rulemaking for revisions of certain of its regulations pertaining to E&P wastes or sign a determination that revision of the regulations is not necessary. If EPA proposes a rulemaking for revised E&P waste regulations, the consent decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. If the exemption covering E&P wastes is repealed or modified, or if the regulations interpreting the rules regarding the treatment or disposal of this type of waste were changed, our operations could face significantly more stringent regulations, permitting requirements, and other restrictions, which could have a material adverse effect on our business.

Under the terms of our amended and restated omnibus agreement, Holdings will indemnify us for certain potential claims, losses and expenses relating to environmental matters and associated with the operation of the assets contributed to us and occurring before the closing date of our IPO. However, the liability of Holdings for these indemnification obligations is subject to a \$350,000 deductible. Moreover, our assets constitute a substantial portion of Holdings' assets, and Holdings has not agreed to maintain any cash reserve to fund any indemnification obligations under our amended and restated omnibus agreement. In addition, changes in environmental laws occur frequently, and any such changes that result in more stringent and costly requirements would not be covered by the environmental indemnity and could have a material adverse effect on our operations or financial position.

We could incur significant costs in cleaning up contamination that occurs at our facilities.

Petroleum hydrocarbons, saltwater, and other substances and wastes arising from E&P related activities have been disposed of or released on or under many of our sites. At some of our facilities, we have conducted and may continue to conduct monitoring, and we will continue to perform such monitoring and remediation of known contamination until the appropriate regulatory standards have been achieved. These monitoring and remediation efforts are usually overseen by state environmental regulatory agencies. Costs for such remediation activities may exceed estimated costs, and there can be no assurance that the future costs will not be material. It is possible that we may identify additional contamination in the future, which could result in additional remediation obligations and expenses, which could be material.

We and our customers may be exposed to certain regulatory and financial risks related to climate change.

The EPA has adopted regulations under existing provisions of the federal Clean Air Act, that, for example, require certain large stationary sources to obtain Prevention of Significant Deterioration, or PSD, pre-construction permits and Title V operating permits for GHG emissions. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas processing and fractionating facilities, which was expanded in October 2015 to include onshore petroleum and natural gas gathering and boosting activities and natural gas transmission pipelines. Additionally, the U.S. Congress has in the past considered adopting legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap-and-trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances that correspond to their annual emissions of GHGs. In addition, in December 2015, over 190 countries, including the United States, reached an agreement to reduce greenhouse gas emissions. The agreement entered into force in November 2016 after over 70 countries, including the United States, ratified or otherwise consented to be bound by the agreement. However, in June 2017, President Trump announced that the United States plans to withdraw from the agreement and to seek negotiations either to reenter the agreement on different terms or a separately negotiated agreement. In August 2017, the U.S. Department of State officially informed the United Nations of the United States' intent to withdraw from the agreement. The agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the agreement or a separately negotiated agreement are unclear at this time. To the extent that the United States and other countries implement this agreement or impose other climate change regulations on the oil and natural gas industry, it could have an adverse effect on our business. The EPA and other federal and state agencies have also acted to address greenhouse gas emissions in other industries, most notably coal-fired power generation, and as a result could attempt in the future to impose additional regulations on the oil and natural gas industry.

Although it is not possible at this time to estimate how potential future laws or regulations addressing GHG emissions would impact our business, either directly or indirectly, any future federal or state laws or implementing regulations

that may be adopted to address GHG emissions in areas where we operate could require us or our customers to incur increased operating costs. Regulation of GHGs could also result in a reduction in demand for and production of oil and natural gas, which would result in a decrease in demand for our services. We cannot predict with any certainty at this time how these possibilities may affect our operations, but effects could be materially adverse.

Finally, 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 any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas produced by our customers or otherwise cause us to incur significant costs in preparing for or responding to those effects.

Certain plant or animal species could be designated as endangered or threatened, which could limit our ability to expand some of our existing operations or limit our customers' ability to develop new oil and natural gas wells.

The federal Endangered Species Act ("ESA") restricts activities that may affect endangered or threatened species or their habitats. Many states also have analogous laws designed to protect endangered or threatened species. For example, the lesser-prairie chicken was listed as threatened in March 2014, although a district court recently vacated this decision.

Additionally, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the Fish and Wildlife Service was required to make a determination on the listing of more than 250 species as endangered or threatened under the ESA by the end of the Fish and Wildlife Service's 2017 fiscal year.

Although current listings have not had a material impact on our operations, the designation of previously unidentified endangered or threatened species under the ESA or similar state laws could limit our ability to expand our operations and facilities or could force us to incur material additional costs. Moreover, listing such species under the ESA or similar state laws could indirectly, but materially, affect our business by imposing constraints on our customers' operations, including the curtailment of new drilling or a refusal to allow a new pipeline to be constructed.

We have customers in New Mexico, Texas, Oklahoma, Wyoming and North Dakota that have operations within the habitat of the greater sage-grouse and the lesser prairie-chicken, and our own operations are strategically located in proximity to our customers. To the extent these species, or other species that live in the areas where our operations and our customers' operations are conducted, are listed under the ESA or similar state laws, this could limit our ability to expand our operations and facilities, or could force us to incur material additional costs. Moreover, listing such species under the ESA or similar state laws could indirectly, but materially, affect our business by imposing constraints on our customers' operations.

We must comply with worker 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.

Our activities are subject to a wide range of national, state, and local occupational health and safety laws and regulations. These environmental, health, and safety laws and regulations applicable to our business and the business of our customers, including laws regulating the energy industry, and the interpretation or enforcement of these laws and regulations, are constantly evolving. 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, 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 safety and compliance record is also important to our clients, and our failure to maintain safe operations could materially impact our business.

Our business involves many hazards, operational risks, and regulatory uncertainties, some of which may not be fully covered by insurance. If a significant accident or event occurs for which we are not adequately insured or if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, our operations and financial results could be adversely affected.

Risks inherent to our industry, such as lightning strikes, equipment defects, vehicle accidents, explosions, earthquakes, and incidents related to the handling of fluids and wastes, can cause personal injury, loss of life, suspension of operations, damage to formations, damage to facilities, business interruption, and damage to or destruction of property, equipment and the environment. We use fiberglass tanks at our saltwater disposal facilities because fiberglass is less corrosive than other materials traditionally utilized. These tanks are, however, more prone to lightning strikes than traditional tanks, as a result of fiberglass' tendency to store static electricity. The lightning protection systems we employ may not succeed in preventing lightning from damaging a facility. The risks associated with these types of accidents could expose us to substantial liability for personal injury, wrongful death, property damage, pollution and other environmental damages. The frequency and severity of such incidents will affect operating costs, insurability, and relationships with employees and regulators.

Our insurance coverage may be inadequate to cover our liabilities. For instance, while our insurance policies apply to and cover costs imposed on us by retroactive changes in governmental regulations, the costs we incur as a result of

such regulatory changes cannot be known in advance and may exceed our coverage limitations. In addition, we may not be able to maintain adequate insurance in the future at rates we consider reasonable and commercially justifiable, and insurance may not continue to be available on terms as favorable as our current arrangements. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us, or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations, and cash flows. In some cases, electrical storms can damage facility motors or electronics, and it may not be possible to prove to the insurance carrier that such storm caused the damage. We do not carry business interruption insurance on our saltwater disposal facilities and as a result, could suffer a significant loss in revenue that could impact our ability to pay distributions on our units.

Accidents or incidents related to the handling of hydraulic fracturing fluids, saltwater, or other wastes are covered by our insurance against claims made for bodily injury, property damage, or environmental damage and clean-up costs stemming from a sudden and accidental pollution event, provided that we report the event within 30 days after its commencement. The coverage applies to incidents the company is legally obligated to pay resulting from pollution conditions caused by covered operations. We may not have coverage if the operator is unaware of the pollution event and unable to report the “occurrence” to the insurance company within the required time frame. Although we have coverage for gradual, long-term pollution events at certain locations, this coverage does not extend to all places where we may be located or where we may do business. We also may have liability exposure if any pipelines or gathering systems transporting water to our saltwater disposal facilities develop a leak (depending upon the terms of the insurance contracts at issue).

On November 29, 2018, a production inspector employed by CEM-TIR, suffered a fatal injury while working at a client’s jobsite. The injury occurred while the employee was performing a procedure inconsistent with his job duties, at the direction of the client’s employee. CEM-TIR had no knowledge or control over the work that was performed by the employee. An OSHA investigation determined that neither CEM-TIR nor TIR were at fault, and instead issued citations to the client. Although no claims have been made against CEM-TIR or TIR, the client has informed us that if any claims are made against the client as a result of the fatality, they will seek indemnification from TIR pursuant to a provision in a master services agreement between TIR and the client.

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 saltwater disposal facilities are located exclusively in North Dakota. This concentration could disproportionately expose us to operational, economic, and regulatory risk in these areas. Additionally, after the sale of both of our Texas saltwater disposal facilities in 2018, our saltwater disposal facilities currently comprise eight owned and one managed facility. Any operational, economic or regulatory issues at a single facility could have a material adverse impact on us. Due to the lack of diversification in our assets and the location of our assets, adverse developments in our markets, including, for example, transportation constraints, adverse regulatory developments, or other adverse events at one of our saltwater disposal facilities, could have a significantly greater impact on our financial condition, results of operations, and cash flows than if we were more diversified.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas and our customers' drilling and production activities, and therefore the amount of drilling and production waste provided to us for treatment and disposal. Management cannot predict the impact of the changing demand for oil and natural gas services and products, and any major changes may have a material adverse effect on our business, financial condition, results of operations, and cash flows.

New technology, including those involving recycling of saltwater or the replacement of water in fracturing fluid, may hurt our competitive position.

The saltwater disposal industry is subject to the introduction of new waste treatment and disposal techniques and services using new technologies including those involving recycling of saltwater, some of which may be subject to patent protection. As competitors and others use or develop new technologies or technologies comparable to ours in the future, we may lose market share or be placed at a competitive disadvantage. For example, some companies have successfully used propane as the fracturing fluid instead of water. Further, we may face competitive pressure to implement or acquire certain new technologies at a substantial cost. Some of our competitors may have greater financial, technical and personnel resources than we do, which may allow them to gain technological advantages or implement new technologies before we can. Additionally, we may be unable to implement new technologies or products at all, on a timely basis, or at an acceptable cost. New technology could also make it easier for our customers to vertically integrate their operations or reduce the amount of waste produced in oil and natural gas drilling and production activities, thereby reducing or eliminating the need for third-party disposal. Limits on our ability to effectively use or implement new technologies may have a material adverse effect on our business, financial condition and results of operations.

Technology advancements in connection with alternatives to hydraulic fracturing could decrease the demand for our saltwater disposal facilities.

Some oil and natural gas producers are focusing on developing and utilizing non-water fracturing techniques, such as techniques that utilize propane, carbon dioxide, or nitrogen instead of water. If our producing customers begin to shift their fracturing techniques to waterless fracturing in the development of their wells, our saltwater disposal services could be materially impacted because these wells would not produce flowback water.

We may be unable to ensure that customers will continue to utilize our services or facilities and pay rates that generate acceptable margins for us.

We cannot ensure that customers will continue to pay rates that generate acceptable margins for us. Our margins for Water Services could decrease if the volume of saltwater processed and disposed of by our customers' decreases or if we are unable to increase the rates charged to correspond with increasing costs of operations. Our revenues and profitability for Pipeline Inspection and Pipeline & Process Services could decrease if the demand for our inspectors decrease, if our safety record declines, or we are unable to obtain affordable insurance, if we are unable to recruit and retain qualified inspectors, or if we are unable to increase the daily and hourly rates charged to correspond with any potential increasing costs of operations. In addition, new agreements for our services in these business segments may not be obtainable on terms acceptable to us or, if obtained, may not be obtained on terms favorably consistent with current practices, in which case our revenue and profitability could decline. We also cannot ensure that the parties from whom we lease, license, or otherwise occupy the land on which certain of our facilities are situated, or the parties from whom we lease certain of our equipment, will renew our current leases, licenses, or other occupancy agreements upon their expiration on commercially reasonable terms or at all. Any such failure to honor the terms of the leases or licenses or renew our current leases or licenses could have a material adverse effect on our financial position, results of operations, and cash flows.

We may be unable to attract and retain a sufficient number of skilled and qualified workers.

The delivery of our water and environmental services and products requires personnel with specialized skills and experience who can perform physically demanding work. The saltwater disposal industry has experienced a high rate of employee turnover as a result of the volatility of the oilfield service industry and the demanding nature of the work, and workers may choose to pursue employment in fields that offer a less demanding work environment. In addition, Pipeline Inspection and Pipeline & Process Services are dependent on specialized inspectors, who must undergo specific training prior to performing inspection and integrity services.

Our ability to be productive and profitable will depend upon our ability to employ and retain skilled workers. In addition, our ability to expand our operations depends in part on our ability to increase the size of our skilled labor force. The demand for skilled workers is high, and the supply of skilled workers is limited. A significant increase in the wages paid by our competitors or the unionization of groups of our employees, could result in a reduction of our skilled labor force, increases in the wage rates that we must pay, or both. Likewise, laws and regulations to which we are, or may in the future become subject, could increase our labor costs or subject us to liabilities to our employees. In addition, the U.S. customers in Pipeline Inspection and Pipeline & Process Services could choose to hire our inspectors directly. If any of these events were to occur, our capacity and profitability could be diminished and our growth potential could be impaired.

Our ability to operate our business effectively could be impaired if affiliates of our general partner fail to attract and retain key management personnel.

We depend on the continuing efforts of our executive officers and other key management personnel, all of whom are employees of affiliates of our general partner. Additionally, neither we, nor our subsidiaries, have employees. CEM LLC and its affiliates are responsible for providing the employees and other personnel necessary to conduct our operations. All of the employees that conduct our business are employed by affiliates of our general partner, including our Chairman, Chief Executive Officer and President, Peter C. Boylan III. The loss of any member of our management or other key employees could have a material adverse effect on our business. Consequently, our ability to operate our business and implement our strategies will depend on the continued ability of affiliates of our general partner to attract and retain highly skilled management personnel with industry experience. Competition for these persons is intense. Given our size, we may be at a disadvantage, relative to our larger competitors, in the competition for these personnel. We may not be able to continue to employ our senior executives and other key personnel, or attract and retain qualified personnel in the future, and our failure to retain or attract our senior executives and other key personnel could have a material adverse effect on our ability to effectively operate our business.

Our business would be adversely affected if we, or our customers, experience significant interruptions.

We are dependent upon the uninterrupted operations of our saltwater disposal facilities for the processing of saltwater, as well as the operations of third-party facilities, such as our oil and natural gas producing customers, for uninterrupted demand of our water and environmental services. Any significant interruption at these facilities, or inability to transport products to or from the third-party facilities to our saltwater disposal facilities, for any reason, would adversely affect our results of operations, cash flow, and ability to make distributions to our unitholders. Operations at our facilities and at the facilities owned or operated by our customers 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 lightning strikes, hurricanes, seismic activity such as earthquakes, fires and floods;

loss of electricity or power;

explosion, breakage, loss of power, 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 the facilities;

disruptions in the supply of saltwater to our facilities;

failure of third-party pipelines, pumps, equipment or machinery; and

governmental mandates, restrictions, or rules and regulations.

In addition, there can be no assurance that we are adequately insured against such risks because the Partnership does not carry business interruption insurance. As a result, our revenue and results of operations could be materially adversely affected.

The amount of cash we have available for distribution to holders of our common units depends primarily on our cash flow, rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow, and not solely on profitability. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes, and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

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

Interest rates may continue to increase in the future. As a result, interest rates on our credit facilities, or future credit facilities and debt offerings, could be higher than current levels, causing our financing costs to increase accordingly. Our common 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 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 equity or incur debt for acquisitions or other purposes and to make cash distributions at our intended levels.

A failure in our operational and communications systems, loss of power, natural disasters, or cyber security attacks on any of our facilities, or any of our third-parties' facilities on which we rely, may adversely affect our results of operations and financial results.

Our business is dependent upon our operational systems to process a large amount of data and a substantial number of transactions. If any of our financial, operational, or other data processing systems fail or have other significant shortcomings, our financial results could be adversely affected. Our financial results could also be adversely affected if an employee causes our operational or financial systems to fail, either as a result of inadvertent error, or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk that operational system flaws, employee tampering, or manipulation of those systems will result in losses that are difficult to detect.

Due to technological advances, we have become more reliant on technology to help increase efficiency in our business. We use computer programs to help run our financial and operations processes, and this may subject our business to increased risks. Any future cyber security attacks that affect our facilities, communications systems, our customers, or any of our financial data could have a material adverse effect on our business. In addition, cyber-attacks on our customer and employee data may result in a financial loss and may negatively impact our reputation. We do not maintain specialized insurance for possible liability resulting from a cyber-attack on our assets that may shut down all or part of our business. Third-party systems on which we rely could also suffer operational system failure. Any of these occurrences could disrupt our business, result in potential liability or reputational damage, or otherwise have an adverse effect on our financial results.

If we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results accurately or prevent fraud, which would likely have a negative impact on the market price of our common units.

Effective internal controls are necessary for us to provide timely, reliable financial reports, prevent fraud and to operate successfully as a publicly traded partnership. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002 (“Section 404”). For example, Section 404 requires us, among other things, to annually review and report on the effectiveness of our internal controls over financial reporting. Any failure to develop, implement, or maintain effective internal controls, or to improve our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Given the difficulties inherent in the design and operation of internal controls over financial reporting, we can provide no assurance as to our conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404.

During late 2018, we signed agreements with a software provider and with a system integration advisor, under which, we plan to implement a new software system for payroll and human resources management. We expect to implement the new system on January 1, 2020. It is our intent through this new system to improve processes for human resources management, payroll, and other applications as they affect our evolving business model. Any failure(s) during this implementation process to develop, implement, or maintain effective internal controls, or to improve our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Given the difficulties inherent in the design and operation of internal controls over a new system implementation, we can provide no assurance as to our conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404. Ineffective internal controls could subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business, and would likely have a negative effect on the trading price of our common units.

We are required to disclose changes made in our internal control over financial reporting on a quarterly basis, and we are required to assess the effectiveness of our controls annually. We are not an “accelerated filer” as defined in Rule 12b-2 of the Exchange Act, and therefore, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal controls over financial reporting until we become an accelerated filer.

A sustained failure of our information technology systems could adversely affect our business.

An enterprise-wide information system has been developed and integrated into our operations. If our information technology systems are disrupted due to problems with the integration of our information system or otherwise, we may face difficulties in generating timely and accurate financial information. Such a disruption to our information

technology systems could have an adverse effect on our financial condition, results of operations, and cash available for distribution to our unitholders. In addition, we may not realize the benefits we anticipated from the implementation of our enterprise-wide information system.

We recently began the process of implementing a new information technology system to support our payroll, inspector recruitment, and human resource management processes. We expect to implement this new system on January 1, 2020. It is our intent, through this system, to integrate the major facets of our organization in order to improve planning, development, processes, sales, human resources management, and other applications as they affect our evolving business model. We may not realize the benefits we anticipate should all or a part of the system implementation process prove to be ineffective.

Risks Inherent in an Investment in Us

Our general partner and its affiliates, including Holdings, have conflicts of interest with us and limited fiduciary duties to us and our unitholders, and they may favor their own interests to our and our unitholders' detriment. Additionally, we have no control over the business decisions and operations of Holdings, and Holdings is under no obligation to adopt a business strategy that favors us.

As of December 31, 2018, Holdings and its affiliates own an approximate 64.0% common unit interest in us and own and control our general partner and appoint all the officers and directors of our general partner. As of December 31, 2018, an affiliate of Holdings owns all of the preferred unit interests in us. Although our general partner has a duty to manage us in a manner that is in the best interests of our partnership and our unitholders, the directors and officers of our general partner also have a fiduciary duty to manage our general partner in a manner that is in the best interests of its owner, Holdings. Conflicts of interest may arise between Holdings and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates, including Holdings, over the interests of our common unitholders. These conflicts include, among others, the following situations:

neither our partnership agreement nor any other agreement requires Holdings to pursue a business strategy that favors us or utilizes our assets, which could involve decisions by Holdings to invest in competitors, pursue and grow particular markets, or undertake acquisition opportunities for itself. Holdings' directors and officers have a fiduciary duty to make these decisions in the best interests of Holdings;

our general partner is allowed to take into account the interests of parties other than us, such as Holdings, in resolving conflicts of interest;

Holdings may be constrained by the terms of its debt instruments from taking actions, or refraining from taking actions, that may be in our best interests;

our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limiting our general partner's liabilities and restricting the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty;

except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;

our general partner will determine the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities, and the creation, reduction or increase of cash reserves, each of which can affect the amount of cash that is distributed to our unitholders;

expenditures, which would not reduce operating surplus, or a maintenance capital expenditure, which would reduce our operating surplus, and whether to set aside cash for future maintenance capital expenditures on certain

of our assets that will need extensive repairs during their useful lives. This determination can affect the amount of available cash from operating surplus that is distributed to our unitholders and to our general partner, and the amount of adjusted operating surplus generated in any given period;

our general partner will determine which costs incurred by it are reimbursable by us;

our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions;

our partnership agreement permits us to classify up to \$10.0 million as operating surplus, even if it is the surplus generated from asset sales, non-working capital borrowings, or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions to our general partner in respect of the general partner interest or the incentive distribution rights;

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

our general partner intends to limit its liability regarding our contractual and other obligations;

our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if it and its affiliates own more than 80.0% of the common units;

our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates;

our general partner decides whether to retain separate counsel, accountants or others to perform services for us;

our general partner may or may not provide financial support to the Partnership. They may also require compensation for financial support in the form of additional units, preferred equity, dividend reinvestment plan, and other mechanisms;

our general partner may decide to issue additional Partnership common units to the general public, thus diluting current unitholders' ownership interests. This action could result in lower distributions to our common unitholders; and

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 the incentive distribution rights without the approval of the conflicts committee of the board of directors of our general partner, which we refer to as our conflicts committee, or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Under the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers, directors, and owners. 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. 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. This may create actual and potential conflicts of interest between us and affiliates of our general partner, and result in less than favorable treatment of us and our unitholders. Please read "Item 13 – Certain Relationships and Related Party Transactions – Conflicts of Interest and Duties,"

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

Our partnership agreement requires that we distribute all of our available cash to our unitholders. As a result, we expect to rely primarily upon external financing sources, including commercial bank borrowings, and the issuance of

debt and equity securities, to fund our acquisitions and expansion capital expenditures. Therefore, to the extent we are unable to finance our growth externally, our cash distribution policy will significantly impair our ability to grow. In addition, because we will distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement, and we do not anticipate there being limitations in our indebtedness, on our ability to issue additional units, including units ranking senior to our common units as to distributions or in liquidation or that have special voting rights and other rights, and our unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any such additional units. The incurrence of additional commercial borrowings, or other debt to finance our growth strategy, would result in increased interest expense, which, in turn, may reduce the amount of cash that we have available to distribute to our unitholders.

Our general partner's discretion in establishing cash reserves may reduce the amount of cash we have available 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, the partnership agreement permits the general partner to reduce available 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 cash we have available to distribute to 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 the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. 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, free of any duties to us and our unitholders, other than the implied contractual covenant of good faith and fair dealing. This provision entitles our general partner to consider only the interests and factors that it desires, and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates, or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate corporate opportunities among us and its affiliates;

- whether to exercise its limited call right;

- whether to seek approval by the conflicts committee of the board of directors of our general partner to address and resolve a conflict of interest;

- how to exercise its voting rights with respect to the units it owns;

- whether to elect to reset target distribution levels;

- whether to transfer the incentive distribution rights or any units it owns to a third party; and

- whether or not to consent to any merger, consolidation or conversion of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a unitholder is treated as having consented to the provisions in our partnership agreement, including the provisions discussed above. Please read “*Item 13 – Certain Relationships and Related Party Transactions – Conflicts of Interest and Duties.*”

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that counterparties to such agreements have recourse only against our assets and not against our general partner or its assets or any affiliate of our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner’s fiduciary duties, even if we could have obtained terms that are more favorable without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

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

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

provides that whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the determination or the decision to take or decline to take such action was in the best interests of our partnership, 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;

provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners 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 intentional fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was unlawful; and

provides that our general partner will not be in breach of its obligations under our partnership agreement or its fiduciary duties to us or our limited partners if a transaction with an affiliate, or the resolution of a conflict of interest is approved in accordance with, or otherwise meets, the standards set forth in our partnership agreement.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, our partnership agreement provides that any determination by our general partner must be made in good faith, and that our conflicts committee and the board of directors of our general partner are entitled to a presumption that they acted in good faith. 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. Please read “*Item 13 – Certain Relationships and Related Party Transactions – Conflicts of Interest and Duties.*”

Cost reimbursements and fees due to Holdings for services provided to us or on our behalf following the termination of our amended and restated omnibus agreement could be substantial and will reduce our cash available for distribution to our unitholders.

Pursuant to our amended and restated omnibus agreement, prior to making any distributions to our unitholders, we pay Holdings a quarterly administrative fee of \$1.0 million for the provision of certain general and administrative expenses. For year ending December 31, 2018, all quarterly administrative fees were paid (\$4.0 million). However, during the years ending December 31, 2017 and 2016, Holdings provided sponsor support to the Partnership by waiving payment of the quarterly administrative fee for two quarters and four quarters (\$2.0 million and \$4.0 million), respectively. Holdings received no consideration for this support. In the future, Holdings may require appropriate compensation if it provides any future additional support. This fee is subject to increase by an amount equal to the producer price index (“PPI”) plus one percent or, with the concurrence of the conflicts committee, in the event of an expansion of our operations, including through acquisitions or internal growth. This administrative fee will increase to \$4.5 million in 2019, based on the cumulative increase in the PPI since the inception of the omnibus agreement. In the event of termination of our amended and restated omnibus agreement, in lieu of the quarterly fee, we will be required by our partnership agreement to reimburse Holdings and its affiliates for all costs and expenses that they incur on our behalf for managing and controlling our business and operations, at which time our payment for these services could increase. Such an increase could be substantial. Our partnership agreement provides that Holdings will determine in good faith the expenses that are allocable to us. Furthermore, Holdings and its affiliates will allocate other expenses related to our operations to us and may provide us other services for which we will be charged fees as determined by Holdings. Payments to Holdings and its affiliates following the termination of our amended and restated omnibus agreement could be substantial and will reduce the amount of cash we have available to distribute to unitholders.

Unitholders have very limited voting rights and, even if they are dissatisfied, they cannot remove our general partner without its consent.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management’s decisions regarding our business. For example, unlike holders of stock in a public corporation, unitholders will not have “say-on-pay” advisory voting rights. Unitholders did not elect our general partner or the board of directors of our general partner, and will have no right to elect our general partner or the board of directors of our general partner on an annual or other continuing basis. The board of directors of our general partner is chosen by the member of our general partner, which is a wholly-owned subsidiary of Holdings. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. 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.

The vote of the holders of at least 66^{2/3}% of all outstanding common units is required to remove our general partner. As of March 11, 2019, Holdings and its affiliates own approximately 64.1% of our outstanding common units. Therefore, the unitholders will be unable initially to remove our general partner without its consent, because our general partner and its affiliates own sufficient units to be able to prevent its removal.

Furthermore, unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20.0% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees, and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter.

Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Our general partner interest or the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of Holdings to transfer its membership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own choices.

We may issue additional common units and other equity interests ranking junior to the Series A Preferred Units without unitholder approval, which would dilute unitholders' existing ownership interests.

At any time, we may issue an unlimited number of general partner interests or limited partner interests of any type without the approval of our unitholders and our unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any such general partner interests or limited partner interests, except that, subject to certain limited exceptions, we will need the consent of 66^{2/3}% of the outstanding Series A Preferred Units to issue any additional Series A Preferred Units or any class or series of partnership interests that, with respect to distributions on such partnership interests or distributions in respect of such partnership interests upon our liquidation, dissolution and winding up, ranks equal to or senior to the Series A Preferred Units. Further, there are no limitations in our partnership agreement on our ability to issue equity securities that rank equal, or senior to, our common units as to distributions, or in liquidation, or that have special voting rights and other rights. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

our existing unitholders' proportionate ownership interest in us will decrease;

the amount of cash we have available to distribute on each unit may decrease;

the ratio of taxable income to distributions may increase;

the relative voting strength of each previously outstanding unit may be diminished; and

the market price of our common units may decline.

The issuance by us of additional general partner interests may have the following effects, among others, if such general partner interests are issued to a person who is not an affiliate of Holdings:

management of our business may no longer reside solely with our current general partner; and

affiliates of the newly admitted general partner may compete with us, and neither that general partner, nor such affiliates, will have any obligation to present business opportunities to us.

Holdings or its unitholders, directors or officers may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

As of March 11, 2019, Holdings and CEP-TIR together hold 6,957,349 common units. Additionally, we have agreed to provide Holdings and CEP-TIR with certain registration rights under applicable securities laws. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Affiliates of our general partner, including, but not limited to, Holdings, may compete with us, and neither our general partner nor its affiliates have any obligation to present business opportunities to us.

Neither our partnership agreement, nor our amended and restated omnibus agreement, will prohibit Holdings 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 Holdings. Any such 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. Moreover, except for the obligations set forth in our amended and restated omnibus agreement, neither Holdings, nor any of its affiliates, have a contractual obligation to offer us the opportunity to purchase additional assets from it, and we are unable to predict whether, or when, such an offer may be presented and acted upon. As a result, competition from Holdings and other affiliates of our general partner could materially and adversely impact our results of operations and distributable cash flow.

Our right of first offer on certain of Holdings' assets is subject to risks and uncertainty, and ultimately we may not acquire any of those assets.

Our amended and restated omnibus agreement provides us with a right of first offer on certain assets owned by, and ownership interests held by Holdings and its subsidiaries, that they decide to sell during the five-year period following the closing of our IPO. The consummation and timing of any acquisition by us of the assets covered by our right to first offer will depend upon, among other things, our ability to reach an agreement with Holdings on price and other terms, and our ability to obtain financing on acceptable terms. 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 right of first offer, and Holdings is under no obligation to accept any offer that we may choose to make or to enter into any commercial agreements with us. For these or a variety of other reasons, we may decide not to exercise our right of first offer when we are permitted to do so, and our decision will not be subject to unitholder approval. In addition, our right of first offer may be, upon a change of control of our general partner, or by agreement between us and Holdings, terminated by Holdings at any time after it no longer controls our general partner.

Our general partner has a limited call right that may require our unitholders to sell their common units at an undesirable time or price.

If at any time, our general partner and its affiliates own more than 80.0% of our then-outstanding common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, unitholders may be required to sell their common units at an undesirable time or price, and may not receive any return on unitholders' investment. Unitholders may also incur a tax liability upon a sale of their units. As of March 11, 2019, Holdings and its affiliates own 64.1% of our common units and therefore are not currently able to exercise the call right.

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

Under certain circumstances, unitholders may have to repay amounts wrongfully distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of 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. Transferees of common units are liable for the obligations of the transferor to make contributions to the partnership that are known to the transferee at the time of the transfer and for unknown obligations if the liabilities could be determined from our partnership agreement. 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.

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

As of December 31, 2018, there are only 4,261,755 publicly traded common units held by public unitholders. As of March 11, 2019, Holdings and CEP-TIR own 6,957,349 common units representing an aggregate 57.9% of our common units. We do not know how liquid our trading market might be. Additionally, the lack of liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units, and limit the number of investors who are able to buy the common units. In addition, our Series A Preferred Units may be converted into common units at the then-applicable conversion rate at the earlier of (i) May 29, 2021 or (ii) immediately prior to a liquidation of us.

Our general partner, or any transferee holding incentive distribution rights, may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to its incentive distribution rights, without the approval of our conflicts committee 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, at any time units are outstanding and the holder of the incentive distribution rights has received distributions on its incentive distribution rights at the highest level to which it is entitled (50.0%) for each of the prior four consecutive fiscal quarters and the amount of such distribution did not exceed the adjusted operating surplus for such quarter, 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, the holder of the incentive distribution rights will be entitled to receive a number of common units equal to that number of common units that would have entitled the holder to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions on the incentive distribution rights in such two quarters. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion. It is possible, however, that our general partner could exercise this reset election at a time when it is experiencing, or expects to experience, declines in cash distributions related to the incentive distribution rights and may, therefore, desire the holder of the incentive distribution rights be issued common units, rather than retain the right to receive distributions based on the initial target distribution levels. This risk could be elevated if our incentive distribution rights 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 they would have otherwise received had we not issued new common units in connection with resetting the target distribution levels. Additionally, our general partner has the right to transfer all or any portion of our incentive distribution rights at any time, and such transferee shall have the same rights as the general partner relative to resetting target distributions if our general partner concurs that the tests for resetting target distributions have been fulfilled.

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

Our common units trade on the NYSE. Because we are a publicly traded limited partnership, the NYSE 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. Additionally, any future issuance of additional common units or other securities, including to affiliates, will not be subject to the NYSE's shareholder approval rules that apply to a corporation. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

The incentive distribution rights of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its incentive distribution rights to a third party, at any time, without the consent of our unitholders. If our general partner transfers its incentive distribution rights to a third party, but retains its general partner interest, our general partner 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 its incentive distribution rights. For example, a transfer of incentive distribution rights by our general partner could reduce the likelihood that Holdings, which owns our general partner, will sell or contribute additional assets to us, as Holdings would have less of an economic incentive to grow our business, which, in turn, would impact our ability to grow our asset base.

A unitholder's liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. A unitholder could be liable for any and all of our obligations as if a unitholder were a general partner, if a court or government agency were to determine that unitholders' right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other actions under our partnership agreement constitute "control" of our business.

Our Series A Preferred Units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of our common units.

Our Series A Preferred Units rank senior to our common units with respect to distribution rights and rights upon liquidation. These preferences could adversely affect the market price for our common units or could make it more difficult for us to sell our common units in the future.

In addition, until the conversion of the Series A Preferred Units into common units or their redemption, holders of the Series A Preferred Units will receive cumulative quarterly distributions equal to 9.5% per annum plus accrued and unpaid distributions. With respect to any quarter up to and including the quarter ending June 30, 2021, our general partner may elect to pay such quarterly distribution in cash, in-kind in the form of additional Series A Preferred Units or in a combination thereof, provided that a minimum of 2.5% of such distribution will be paid in cash unless the holders of the Series A Preferred Units otherwise agree. For any quarter ending after June 30, 2021, the quarterly distribution will be paid in cash. Each holder of the Series A Preferred Units has the right to share in any special distributions by us of cash, securities or other property pro rata with the common units on an as-converted basis, subject to customary adjustments. Accordingly, we cannot pay any distributions on any junior securities, including any of the common units, prior to paying the quarterly distribution payable to the Series A Preferred Units, including any previously accrued and unpaid distributions. Our obligation to pay distributions on our Series A Preferred Units could impact our liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions and other general partnership purposes. Our obligations to the holders of the Series

A Preferred Units could also limit our ability to obtain additional financing or increase our borrowing costs, which could have an adverse effect on our financial condition.

The terms of our Series A Preferred Units contain covenants that may limit our business flexibility.

The terms of our Series A Preferred Units contain covenants preventing us from taking certain actions without the approval of the holders of 66^{2/3}% of the outstanding Series A Preferred Units, voting separately as a class. The need to obtain the approval of holders of the Series A Preferred Units before taking these actions could impede our ability to take certain actions that management or the Board of Directors of our General Partner may consider to be in the best interests of our unitholders.

The affirmative vote of 66^{2/3}% of the outstanding Series A Preferred Units, voting separately as a class, is necessary to amend our partnership agreement in any manner that is materially adverse to any of the rights, preferences and privileges of the Series A Preferred Units. The affirmative vote of 66^{2/3}% of the outstanding Series A Preferred Units voting separately as a class, is necessary to, among other things issue, authorize or create any additional Series A Preferred Units or any class or series of partnership interests that, with respect to distributions on such partnership interests or distributions in respect of such partnership interests upon our liquidation, dissolution and winding up, ranks equal to or senior to the Series A Preferred Units.

Tax Risks

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes. If the Internal Revenue Service (“IRS”) were to treat us as a corporation for U.S. federal income tax purposes, which would subject us to entity-level taxation, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes.

Despite the fact that we are a limited partnership under Delaware law, it is possible, in certain circumstances, for a partnership such as ours, to be treated as a corporation for U.S. federal income tax purposes. A change in our business, 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 federal income tax on our taxable income at the corporate tax rate, which is currently at 21.0%, and would likely pay state and local income tax at varying rates. Distributions would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to a unitholder. Because a tax would be imposed upon us as a corporation, our cash available for distribution to a unitholder would be substantially reduced. Therefore, if we were treated as a corporation for federal income tax purposes, there would be a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

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

If we were subjected to a material amount of additional entity-level taxation by individual states, counties, or cities, it would reduce our cash available for distribution to our unitholders.

Changes in current state, county, or city law may subject us to additional entity-level taxation by individual states, countries, or cities. Several states have subjected, or are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to a unitholder. Our partnership agreement provides that, if a law is enacted, or existing law is modified or interpreted in a manner that subjects us to entity-level taxation, the minimum quarterly distribution amount, and the target distribution levels, may be adjusted to reflect the impact of that law on us.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress and the President have periodically considered substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships, including the elimination of partnership tax treatment for publicly traded partnerships. Any modification to the U.S. federal income tax laws and interpretations thereof, may, or may not, be retroactively applied, and could make it more difficult or impossible to meet the qualifying income exception upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any such changes will ultimately be enacted. However, it is possible that a change in law could affect us, and any such changes could negatively impact the value of an investment in our common units.

Our unitholders' share of our income will be taxable to them for U.S. federal income tax purposes even if they do not receive any cash distributions from us.

Because a unitholder will be treated as a partner, to whom we will allocate taxable income that could be different in amount than the cash we distribute, a unitholder's allocable share of our taxable income will be taxable to it, which may require the payment of federal income taxes and, in some cases, state and local income taxes, on its share of our taxable income even if it receives no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

If the IRS contests the U.S. federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes. The IRS may adopt positions that differ from the positions we take, and the IRS's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and such positions may not ultimately be sustained. A court may not agree with some or all of the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse impact on the market for our common units, and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner, because the costs will reduce our cash available for distribution to our unitholders and for incentive distributions to our general partner.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders 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 may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Generally, we expect to elect to have our general partner and our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, but there can be no assurance that such election will be effective in all circumstances. If we are unable to have our general partner and our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties, and interest, our cash available for distribution to our unitholders might be substantially reduced.

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

If our unitholders sell common units, they will recognize a gain or loss for U.S. federal income tax purposes equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of their allocable share of our net taxable income decrease their tax basis in their 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 the unitholder if it sells such common units at a price greater than its tax basis in those common units, even if the price received is less than its original cost. Furthermore, a substantial portion of the amount realized on any sale

of unitholders' common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of cash received from the sale.

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

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file federal income tax returns, and pay tax on their share of our taxable income. If a unitholder is a tax-exempt entity or a non-U.S. person, such unitholder should consult a tax advisor before investing in our common units.

Some of our activities may not generate qualifying income, and we conduct these activities in separate subsidiaries that are treated as corporations for U.S. federal income tax purposes. Corporate U.S. federal income taxes paid by these subsidiaries reduce our cash available for distribution.

In order to maintain our status as a partnership for U.S. federal income tax purposes, 90% or more of our gross income in each tax year must be qualifying income under Section 7704 of the Internal Revenue Code. To ensure that 90% or more of our gross income in each tax year is qualifying income, we currently conduct the portions of our business unrelated to these operations in separate subsidiaries that are treated as corporations for U.S. federal income tax purposes. These corporate subsidiaries will be subject to corporate-level tax, which reduces the cash available for distribution to us and, in turn, to our unitholders. If the IRS were to successfully assert that any corporate subsidiary has more tax liability than we anticipate, or legislation were enacted that increased the corporate tax rate, our cash available for distribution to our unitholders would be further reduced.

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

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

We prorate our items of income, gain, loss, and deduction for U.S. federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month, instead of on the basis of the date a particular 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 prorate our items of income, gain, loss, and deduction for federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred.

The U.S. Department of the Treasury and the IRS have issued Treasury Regulations that permit publicly traded partnerships to use a monthly simplifying convention that is similar to ours, but they do not specifically authorize all aspects of the proration method we have adopted. If the IRS were to successfully challenge this method, we could be required to change the allocation of items of income, gain, loss, and deduction among our unitholders.

A unitholder whose common units are loaned to a "short seller" to effect a short sale of common units may be considered as having disposed of those common units. If so, he would no longer be treated for U.S. federal income 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 a unitholder whose common units are loaned to a "short seller" to effect a short sale of common units may be considered as having disposed of the loaned common units, he may no longer be treated for U.S. federal income 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 to the short seller, 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.

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, and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss, and deduction allocable to our unitholders, in certain circumstances, including when we issue additional units, we must 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 amount, character, and timing of taxable income or loss allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of our common units, or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

We may be required to deduct and withhold amounts from distributions to foreign unitholders related to withholding tax obligations arising from the sale or disposition of our units by foreign unitholders.

Upon the sale, exchange, or other disposition of a unit by a foreign unitholder, the transferee is generally required to withhold 10% of the amount realized on such sale, exchange, or other disposition, if any portion of the gain on such sale, exchange, or other disposition would be treated as effectively connected with a U. S. trade or business. If the transferee fails to satisfy this withholding requirement, we will be required to deduct and withhold such amount (plus interest) from future distributions to the transferee. Because the "amount realized" would include a unitholder's share of our nonrecourse liabilities, 10% of the amount realized could exceed the total cash purchase price for such disposed units. Due to this fact, our inability to match transferors and transferees of units, and other uncertainty surrounding the application of these withholding rules, the U. S. Department of the Treasury and the IRS have currently suspended these rules for transfers of certain publicly traded partnership interests, including transfers of our units, until regulations or other guidance has been issued. It is unclear when such regulations or other guidance will be issued.

As a result of investing in our common units, a unitholder may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to U.S. federal income taxes, our unitholders are likely subject to other taxes, including 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 control property now, or in the future, even if they do not live in any of those jurisdictions. Our unitholders are likely required to file 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 property or conduct business in many states, most of which impose an income tax on individuals, corporations, and other entities. As we make acquisitions, or expand our business, we may control assets or conduct business in additional states that impose a personal income tax. It is each unitholder's responsibility to file all federal, state, and local tax returns. Unitholders should consult their tax advisors.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not Applicable.

ITEM 2. PROPERTIES

Our Properties

We have an aggregate maximum daily disposal capacity of 108,800 barrels in the following saltwater disposal facilities, all of which were built using completion techniques consistent with current industry practices and utilizing well depths of at least 5,300 feet to 6,200 feet with injection intervals beginning at least 5,000 feet beneath the surface. Our permitted capacity is much higher.

Location	County	In-service Date	Leased / Owned (3)
Tioga, ND	Williams	June 2011	Owned
Manning, ND	Dunn	December 2011	Owned
Grassy Butte, ND	McKenzie	May 2012	Leased
New Town, ND (1)	Mountrail	June 2012	Leased
Williston, ND (1)	Williams	August 2012	Owned
Stanley, ND	Mountrail	September 2012	Owned
Belfield, ND	Billings	October 2012	Leased
Watford City, ND (1), (2)	McKenzie	May 2013	Leased

Arnegard, ND (1) McKenzie August 2014 Leased

- (1) Currently receives piped water.
- (2) We own a 25.0% noncontrolling interest in this saltwater disposal facility.
- (3) Some facilities are constructed on land that is leased under long-term arrangements.

We lease general office space at our corporate headquarters located at 5727 S. Lewis Ave., Suite 300, Tulsa, Oklahoma 74105. The lease expires in November of 2024, unless terminated earlier under certain circumstances specified in our lease. An affiliated entity leases office space in Houston, TX that is shared by our Pipeline Inspection and Pipeline & Process Services segments, primarily for business development purposes. This lease expires in March of 2020. We also lease a small office in Walnut Creek, CA that expires in March of 2020. Our Pipeline & Process Services segment rents office space and two apartments in Odessa, Texas. These leases expire before December of 2019.

ITEM 3. LEGAL PROCEEDINGS

Fithian v. TIR LLC

On October 5, 2017, a former inspector for TIR LLC and Cypress Energy Management – TIR, LLC (“CEM TIR”) filed a putative collective action lawsuit alleging that TIR LLC, CEM TIR and Cypress Energy Partners – Texas, LLC failed to pay a class of workers overtime in compliance with the Fair Labor Standards Act (“FLSA”) titled James Fithian, et al v. TIR LLC, et al in the United States District Court for the Western District of Texas, Midland Division. The plaintiff subsequently withdrew his action and filed a similar action in Oklahoma State Court, District of Tulsa County. The plaintiff alleges he was a non-exempt employee of TIR LLC and that he and other potential class members were not paid overtime in compliance with the FLSA. The plaintiff seeks to proceed as a collective action and to receive unpaid overtime and other monetary damages, including attorney’s fees. No estimate of potential loss can be determined at this time and TIR LLC, CEM TIR and Cypress Energy Partners – Texas, LLC deny the claims. The defendants plan to continue to vigorously defend these claims and have stayed a counterclaim against the named plaintiff.

On March 28, 2018, the court granted a joint stipulation of dismissal without prejudice in regard to TIR LLC and Cypress Energy Partners – Texas, LLC, as neither of those parties were employers of the plaintiff or the putative class members during the time period that is the subject of the lawsuit. On July 26, 2018, the plaintiff filed a motion for conditional class certification. CEM-TIR subsequently filed pleadings opposing the motion. On January 25, 2019, the court denied the plaintiff’s motion for conditional class certification.

Sun Mountain LLC v. TIR-PUC

On February 27, 2019, Sun Mountain LLC (“Sun Mountain”), a subcontractor of TIR-PUC, filed a lawsuit alleging that TIR-PUC failed to pay invoices amounting to approximately \$3.5 million for services subcontracted to Sun Mountain under TIR-PUC’s agreement to provide services to Pacific Gas and Electric Company. Sun Mountain filed the action in Federal District Court for the Northern District of Oklahoma. TIR-PUC denies that such amounts are owed, as conditions to TIR-PUC’s obligation to make the payments have not been met. The full amount of these invoices is included within *accounts payable* on the accompanying Consolidated Balance Sheet at December 31, 2018. No estimate of potential loss can be determined at this time and TIR-PUC denies the claims.

Other

From time to time, we are subject to legal proceedings and claims that arise in the ordinary course of business. Like other organizations, our operations are subject to extensive and rapidly changing federal and state environmental, health and safety and other laws and regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities.

We are not a party to any other material pending or overtly threatened legal or governmental proceedings, other than proceedings and claims that arise in the ordinary course and are incidental to our business.

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

Our common units are listed on the NYSE under the symbol "CELP."

On March 11, 2019, the closing price for the common units was \$7.69 per unit and there were approximately 3,200 unitholders of record and beneficial owners (held in street name) of the Partnership's common units. The Partnership issued approximately 5,200 federal K-1s to unitholders of record for 2018.

In addition to the common units we issued at our IPO date, we also issued 5,913,000 subordinated units, for which there was no established public trading market. As of December 31, 2016, 5,612,699 of the subordinated units were effectively held by Holdings and its controlled affiliates, either directly or indirectly through its ownership of CEP-TIR. The remaining 300,301 subordinated units were held directly by certain beneficial owners and management. With the payment of the February 2017 quarterly distribution and the fulfillment of other requirements as provided in the partnership agreement, on February 14, 2017, the subordination period with respect to our 5,913,000 subordinated units expired and all outstanding subordinated units converted to common units on a one-for-one basis. The conversion did not impact the total number of our outstanding units representing limited partner interests.

On May 29, 2018 we issued and sold in a private placement 5,769,231 Series A Preferred Units representing limited partner interests in the Partnership (the “Preferred Units”) for a cash purchase price of \$7.54 per Preferred Unit, resulting in gross proceeds to the Partnership of \$43.5 million. The purchaser of the Preferred Units is entitled to receive quarterly distributions that represent an annual return of 9.5% (which amounts to \$4.1 million per year). Of this 9.5% annual return, we will be required to pay at least 2.5% in cash and will have the option to pay the remaining 7.0% in kind (in the form of issuing additional Preferred Units) for the first twelve quarters after the initial sale of the Preferred Units. We paid the first distribution on the Preferred Units in November 2018 of \$1.4 million in cash, which represented the period from May 29, 2018 through September 30, 2018. We also paid a quarterly distribution on the Preferred Units in February 2019 of \$1.0 million in cash.

Our Cash Distribution Policy

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date. It is the Partnership’s intent to continue to make cash distributions to common unitholders on a quarterly basis; however, the Partnership makes no representation or assurances as to the availability of future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors. Our preferred units rank senior to our common units, and we must pay distributions on our preferred units (including any arrearages) before paying distributions on our common units. In addition, the preferred units rank senior to the common units with respect to rights upon liquidation.

Definition of Available Cash

Available cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

less, the amount of cash reserves established by our general partner at the date of determination of available cash for the quarter to:

provide for the proper conduct of our business, which could include, but is not limited to, amounts reserved for capital expenditures, working capital and operating expenses;

comply with applicable law, any of our debt instruments or other agreements; or

provide funds for distributions to our unitholders (including our general partner) for any one or more of the next four quarters;

plus, if our general partner so determines, all or a portion of cash on hand on the date of determination of available cash for the quarter, including cash on hand resulting from working capital borrowings made after the end of the

quarter.

Distributions

Although it is the Partnership's policy to continue to make cash distributions to our common unitholders on a quarterly basis, the Partnership makes no representation or assurances as to the availability of future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial conditions, and other factors. Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter in the following manner:

first, 100.0% to all common unitholders, pro rata, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter; and
thereafter, in the manner described in “*General Partner Interest and Incentive Distribution Rights*” below.

Series A Preferred Units

As of March 11, 2019, we had 5,769,231 Series A Preferred Units outstanding. Until the conversion of the Series A Preferred Units into common units or their redemption, holders of the Series A Preferred Units are entitled to receive cumulative quarterly distributions equal to 9.5% per annum plus accrued and unpaid distributions. With respect to any quarter up to and including the quarter ending June 30, 2021, our general partner may elect to pay such quarterly distribution in cash, in-kind in the form of additional Series A Preferred Units or in a combination thereof, provided that a minimum of 2.5% of such distribution will be paid in cash unless the holders of the Series A Preferred Units otherwise agree. For any quarter ending after June 30, 2021, the quarterly distribution will be paid in cash. We cannot redeem, repurchase or pay any distributions on any junior securities, including any of the common units, prior to paying the quarterly distribution payable to the Series A Preferred Units, including any previously accrued and unpaid distributions.

General Partner Interest and Incentive Distribution Rights

Incentive distribution rights (“IDRs”) represent a common unitholder’s right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. The IDRs are effectively held by the same ownership group that own and control our general partner.

The following discussion assumes there are no arrearages on common units.

If, for any quarter, we have distributed available cash from operating surplus to our common unitholders in an aggregate amount equal to the minimum quarterly distribution, then, our partnership agreement requires that we distribute any additional available cash from operating surplus for that quarter among the common unitholders and the owner(s) of the IDRs in the following manner:

first, 100.0% to all common unitholders, pro rata, until each common unitholder receives a total of \$0.445625 per unit for that quarter (the “first target distribution”);
second, 85.0% to all common unitholders, pro rata, and 15.0% to the owner(s) of the IDRs, until each common unitholder receives a total of \$0.484375 per unit for that quarter (the “second target distribution”);
third, 75.0% to all common unitholders, pro rata, and 25.0% to the owner(s) of the IDRs, until each common unitholder receives a total of \$0.581250 per unit for that quarter (the “third target distribution”); and
thereafter, 50.0% to all common unitholders, pro rata, and 50.0% to the owner(s) of the IDRs.

Securities Authorized for Issuance under Equity Compensation Plans

See “Item 12 — Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters” for information regarding our equity compensation plans as of December 31, 2018.

Unregistered Sales of Equity Securities

None not previously reported on a current report on Form 8-K.

Issuer Purchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA

The following table should be read together with “*Item 7 – Management’s Discussion and Analysis of Financial Condition and Results of Operations*” and the historical financial statements and accompanying notes included in “*Item 8 – Financial Statements and Supplementary Data*.”

Cypress Energy Partners, L.P. (the “Partnership”) is a Delaware limited partnership formed in 2013 to provide independent pipeline inspection and integrity services to producers and pipeline companies and to provide saltwater disposal and other water and environmental services to U.S. onshore oil and natural gas producers and trucking companies. Trading of our common units began January 15, 2014 on the New York Stock Exchange under the symbol “CELP.” At our Initial Public Offering (“IPO”), 4,312,500 of our common units were sold to the general public. The remaining common units and 100% of the subordinated units were constructively owned by affiliates, employees, and directors of the Partnership. With the payment of the February 2017 quarterly distribution and the fulfillment of other requirements provided in the partnership agreement, on February 14, 2017, the subordination period with respect to our 5,913,000 subordinated units expired and all outstanding subordinated units converted to common units on a one-for-one basis.

In connection with the Partnership’s IPO, a 100% ownership interest in the Partnership’s saltwater disposal facilities (the Water Services segment) and a 50.1% interest in the TIR Entities (the Partnership’s Pipeline Inspection segment) were contributed to the Partnership.

Effective February 1, 2015, the Partnership acquired the remaining 49.9% interest in the TIR Entities previously held by affiliates of Holdings. Effective May 1, 2015, the Partnership acquired a 51% interest in Brown (the Pipeline & Process Services segment).

The following table also presents Adjusted EBITDA, which we use in evaluating the performance and liquidity of our business. This financial measure is not calculated or presented in accordance with generally accepted accounting principles, or GAAP. We explain this measure below and reconcile it to net income and net cash from operating activities, its most directly comparable financial measures calculated and presented in accordance with GAAP.

Cypress Energy Partners, L.P.

	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016	Year Ended December 31, 2015(a)	Year Ended December 31, 2014
(in thousands, except cash distributions per unit and operational data)					
Income Statement Data					
Revenues	\$ 314,960	\$ 286,342	\$ 297,997	\$ 371,191	\$ 404,418
Costs of services	270,914	252,739	262,517	326,261	355,355
Gross margin	44,046	33,603	35,480	44,930	49,063
General and administrative	23,744	21,055	21,853	23,795	21,321
Depreciation, amortization and accretion	4,404	4,443	4,861	5,427	6,345
Impairments	—	3,598	10,530	6,645	32,546
Gain on asset disposals, net	4,108	570	—	—	—
Operating income (loss)	20,006	5,077	(1,764)	9,063	(11,149)
Interest expense, net	6,206	7,335	6,559	5,656	3,208
Offering costs	—	—	—	—	446
Net income (loss)	12,098	(1,923)	(9,162)	4,091	(15,179)
Net income (loss) attributable to non-controlling interests	685	(1,110)	(4,499)	599	4,973
Net income (loss) attributable to partners / controlling interests	11,413	(813)	(4,663)	3,492	(20,152)
Balance sheet Data - Period End					
Total assets	\$ 152,853	\$ 163,203	\$ 167,512	\$ 190,882	\$ 187,524
Current portion of long-term debt	—	136,293	—	—	—
Long-term debt	76,129	—	135,699	139,129	75,282
Total owners' equity	54,287	9,985	19,388	40,702	100,428
Cash Flow Data					
Cash flows from operating activities	\$ 15,409	\$ 8,253	\$ 24,819	\$ 26,921	\$ 13,016
Cash flows from investing activities	7,007	(1,041)	(1,330)	(64,879)	(2,286)
Cash flows from financing activities	(31,466)	(10,150)	(21,289)	42,501	(16,030)
Cash distributions per unit (subsequent to IPO) (b)	0.84	0.84	1.63	1.63	1.51
Capital expenditures	5,762	3,345	1,376	1,857	2,286
Other Financial Data					
Adjusted EBITDA	\$ 23,102	\$ 16,640	\$ 19,794	\$ 24,663	\$ 28,499
Adjusted EBITDA attributable to partners / controlling interests	21,883	18,692	22,238	23,147	18,190
Operational Data					
Average number of inspectors (PI segment)	1,214	1,145	1,147	1,392	1,535

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Average revenue per inspector per week	\$ 4,551	\$ 4,499	\$ 4,601	\$ 4,711	\$ 4,773
Average number of field personnel (PPS segment) (c)	23	20	23	33	
Average revenue per field personnel per week	\$ 12,508	\$ 8,887	\$ 11,577	\$ 12,653	
Total barrels of saltwater disposed (in thousands)	14,782	12,588	13,307	18,864	19,066
Average revenue per barrel	\$ 0.80	\$ 0.67	\$ 0.67	\$ 0.78	\$ 1.18

- (a) Activity for the year ended December 31, 2015 includes operations of Brown (PPS segment) from the May 1, 2015 acquisition date to the end of the year.
- (b) Includes February distributions related to the previous quarter ended December 31.
- (c) Represents Brown (PPS segment) personnel from the May 1, 2015 acquisition date.

Non-GAAP Financial Measures

We define Adjusted EBITDA as net income (loss); plus interest expense; depreciation, amortization and accretion expenses; income tax expense; impairments; non-cash allocated expenses; equity-based compensation expense; less certain other unusual or non-recurring items. We define Adjusted EBITDA attributable to limited partners as net income (loss) attributable to limited partners; plus interest expense attributable to limited partners; depreciation, amortization and accretion expenses attributable to limited partners; impairments attributable to limited partners; income tax expense attributable to limited partners; non-cash allocated expenses attributable to limited partners; and equity-based compensation attributable to limited partners; less certain other unusual or non-recurring items attributable to limited partners. We define Distributable Cash Flow as Adjusted EBITDA attributable to limited partners excluding cash interest paid, cash income taxes paid, maintenance capital expenditures, and cash distributions on preferred equity. Adjusted EBITDA, Adjusted EBITDA attributable to limited partners, and Distributable Cash Flow are used as supplemental financial measures by management and by external users of our financial statements, such as investors and commercial banks, to assess:

the financial performance of our assets without regard to the impact of financing methods, capital structure or historical cost basis of our assets;

the viability of capital expenditure projects and the overall rates of return on alternative investment opportunities;

our ability to incur and service debt and fund capital expenditures;

the ability of our assets to generate cash sufficient to make debt payments and to make distributions; and

our operating performance as compared to those of other companies in our industry without regard to the impact of financing methods and capital structure.

We believe that the presentation of these non-GAAP measures provides useful information to investors in assessing our financial condition and results of operations. The GAAP measures most directly comparable to Adjusted EBITDA, Adjusted EBITDA attributable to limited partners, and Distributable Cash Flow are net income (loss) and cash flow from operating activities. These non-GAAP measures should not be considered as alternatives to the most directly comparable GAAP financial measures. Each of these non-GAAP measures exclude some, but not all, items that affect the most directly comparable GAAP financial measures. Adjusted EBITDA, Adjusted EBITDA attributable to limited partners and Distributable Cash Flow should not be considered alternatives to net income (loss), income (loss) before income taxes, net income (loss) attributable to limited partners, cash flows from operating activities, or any other measure of financial performance calculated in accordance with GAAP, as those items are used to measure operating performance, liquidity, or the ability to service debt obligations.

Because Adjusted EBITDA, Adjusted EBITDA attributable to limited partners, and Distributable Cash Flow may be defined differently by other companies in our industry, our definitions of Adjusted EBITDA, Adjusted EBITDA attributable to limited partners, and Distributable Cash Flow may not be comparable to a similarly titled measure of other companies, thereby diminishing their utility.

The following tables present a reconciliation of *net income (loss)* to Adjusted EBITDA and to Distributable Cash Flow, a reconciliation of *net income (loss) attributable to limited partners* to Adjusted EBITDA attributable to limited partners and to Distributable Cash Flow, and a reconciliation of *net cash provided by operating activities* to Adjusted EBITDA and to Distributable Cash Flow for each of the periods indicated.

Reconciliation of Net Income (Loss) to Adjusted EBITDA
and to Distributable Cash Flow

	Years ended December 31,		
	2018	2017	2016
	(in thousands)		
Net income (loss)	\$ 12,098	\$ (1,923)	\$ (9,162)
Add:			
Interest expense	6,206	7,335	6,559
Debt issuance cost write-off	114	—	—
Depreciation, amortization and accretion	5,480	5,545	5,788
Impairments	—	3,598	10,530
Income tax expense	1,318	596	1,195
Non-cash allocated expenses	—	1,750	3,798
Equity based compensation	1,247	1,059	1,086
Foreign currency losses	643	—	—
Less:			
Gains on asset disposals, net	4,004	588	—
Foreign currency gains	—	732	—
Adjusted EBITDA	\$ 23,102	\$ 16,640	\$ 19,794
Adjusted EBITDA attributable to general partner	—	(2,300)	(2,500)
Adjusted EBITDA attributable to non-controlling interests	1,219	248	56
Adjusted EBITDA attributable to limited partners / controlling interests	\$ 21,883	\$ 18,692	\$ 22,238
Less:			
Preferred unit distributions	1,412	—	—
Cash interest paid, cash taxes paid, maintenance capital expenditures	7,611	8,674	6,717
Distributable cash flow	\$ 12,860	\$ 10,018	\$ 15,521

Reconciliation of Net Income Attributable to Limited Partners to Adjusted EBITDA Attributable to Limited Partners
and to Distributable Cash Flow

	Years ended December 31,		
	2018	2017	2016
	(in thousands)		
Net income attributable to limited partners	\$ 11,413	\$ 3,237	\$ 1,635
Add:			
Interest expense attributable to limited partners	6,206	7,335	6,556
Debt issuance costs attributable to limited partners	114	—	—
Depreciation, amortization and accretion attributable to limited partners	4,974	4,978	5,373
Impairments attributable to limited partners	—	2,823	6,409
Income tax expense attributable to limited partners	1,290	580	1,179
Equity based compensation attributable to limited partners	1,247	1,059	1,086
Foreign currency losses attributable to limited partners	643		
Less:			
Gains on asset disposals attributable to limited partners, net	4,004	588	—
Foreign currency gains attributable to limited partners	—	732	—
Adjusted EBITDA attributable to limited partners	21,883	18,692	22,238
Less:			
Preferred unit distributions	1,412	—	—
Cash interest paid, cash taxed paid and maintenance capital expenditures attributable to limited partners	7,611	8,674	6,717
Distributable cash flow	\$ 12,860	\$ 10,018	\$ 15,521

Reconciliation of Net Cash Provided by Operating Activities to Adjusted EBITDA
and to Distributable Cash Flow

	Years ended December 31,		
	2018	2017	2016
	(in thousands)		
Cash flows provided by operating activities	\$ 15,409	\$ 8,253	\$ 24,819
Changes in trade accounts receivable, net	7,165	3,406	(9,871)
Changes in prepaid expenses and other	(1,004)	1,332	(1,350)
Changes in accounts payable and accrued liabilities	(5,440)	(4,471)	(478)
Change in income taxes payable	(87)	365	(662)
Interest expense (excluding non-cash interest)	5,646	6,741	5,989
Income tax expense (excluding deferred tax benefit)	1,267	957	1,219
Other	146	57	128
Adjusted EBITDA	\$ 23,102	\$ 16,640	\$ 19,794
Adjusted EBITDA attributable to general partner	—	(2,300)	(2,500)
Adjusted EBITDA attributable to non-controlling interests	1,219	248	56
Adjusted EBITDA attributable to limited partners / controlling interests	\$ 21,883	\$ 18,692	\$ 22,238
Less:			
Preferred unit distributions	1,412	—	—
Cash interest paid, cash taxes paid, maintenance capital expenditures	7,611	8,674	6,717
Distributable cash flow	\$ 12,860	\$ 10,018	\$ 15,521

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This Management's Discussion and Analysis of Financial Condition and Results of Operations contains a discussion of our business, including a general overview of our properties, our results of operations, our liquidity and capital resources, and our quantitative and qualitative disclosures about market risk.

The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs, and expected performance. The forward-looking statements are dependent upon events, risks, and uncertainties that may be outside our control, including among other things, the risk factors discussed in "Item 1A. Risk Factors" of this Annual Report on Form 10-K. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil and natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, all of which are difficult to predict. In light of these risks, uncertainties, and assumptions, the forward-looking events discussed may not occur. See "Cautionary Remarks

Regarding Forward-Looking Statements” in the front of this Annual Report on Form 10-K.

Overview

We are a growth-oriented master limited partnership formed in September 2013 to provide services to the oil and gas industry. We provide independent pipeline inspection and integrity services to various energy E&P and midstream companies and their vendors in our Pipeline Inspection and Pipeline & Process Services segments throughout the United States and Canada. The Pipeline Inspection segment is comprised of the operations of our TIR Entities and the Pipeline & Process Services segment is comprised of the operations of Brown. We also provide saltwater disposal and other water and environmental services to U.S. onshore oil and natural gas producers and trucking companies through our Water Services segment. We operate nine (eight owned) saltwater disposal facilities, all of which are in the Bakken Shale region of the Williston Basin in North Dakota. We also have a management agreement in place to provide staffing and management services to one 25%-owned saltwater disposal facility in the Bakken Shale region. In all of our business segments, we work closely with our customers to help them comply with increasingly complex and strict environmental and safety rules and regulations applicable to production and pipeline operations, assisting in reducing their operating costs.

How We Generate Revenue

We generate revenue in our Pipeline Inspection segment primarily by providing inspection services on midstream pipelines, gathering systems, and distribution systems, including data gathering and supervision of third-party construction, inspection, and maintenance and repair projects. Our results in this segment are driven primarily by the number of inspectors that perform services for our customers and the fees that we charge for those services, which depend on the type and number of inspectors used on a particular project, the nature of the project, and the duration of the project. The number of inspectors engaged on projects is driven by the type of project, prevailing market rates, the age and condition of customers' midstream pipelines, gathering systems, and distribution systems, and the legal and regulatory requirements relating to the inspection and maintenance of those assets. We charge our customers on a per-inspector basis, including per diem charges, mileage, and other reimbursement items.

We generate revenue in our Pipeline & Process Services segment primarily by providing hydrostatic testing services to major natural gas and petroleum companies and pipeline construction companies. We perform these services on newly-constructed and existing natural gas and crude oil pipelines. We generally charge our customers in this segment on a fixed-bid basis. Bid prices vary based on the size and length of the pipeline being inspected, the complexity of services provided, and the utilization of our work force and equipment. Our results in this segment are driven primarily by the number of field personnel that perform services for our customers, the fees that we charge for those services (which depend on the type and number of field personnel used on a particular project), the type of equipment used and the fees charged for the utilization of that equipment, and the nature and duration of the project.

We generate revenue in our Water Services segment primarily by treating flowback and produced water and injecting the saltwater into our saltwater disposal facilities. Our Water Services results are driven primarily by the volumes of produced water and flowback water we receive and the fees we charge for our services. These fees are charged on a per-barrel basis under contracts that are short-term in nature and vary based on the quantity and type of saltwater disposed, competitive dynamics, and operating costs. The volumes of saltwater disposed at our saltwater disposal facilities are driven by water volumes generated from existing oil and natural gas wells during their useful lives and the development of new wells located near our facilities. Producers' willingness to engage in new drilling is determined by a number of factors, the most important of which are the prevailing and projected prices of oil, natural gas, and natural gas liquids, the cost to drill and operate a well, the availability and cost of capital, and environmental and governmental regulations. We generally expect the level of drilling to positively correlate with long-term trends in prices of oil, natural gas, and natural gas liquids. We also generate revenue by managing one saltwater disposal facility. In addition, for minimal marginal cost, we generate revenue by selling residual oil we recover from the flowback and produced water. Our ability to recover residual oil is dependent upon the residual oil content in the saltwater we treat, which is, among other things, a function of water type, chemistry, source, and temperature. Generally, where outside temperatures are lower, there is less residual oil content and separation is more difficult. Thus, our residual oil recovery during the winter season is usually lower than our recovery during the summer season. Additionally, residual oil content will decrease if, among other things, producers begin recovering higher levels of residual oil in saltwater prior to delivering such saltwater to us for treatment.

How We Evaluate Our Operations

Our management uses a variety of financial and operating metrics to analyze our performance. We view these metrics as significant factors in assessing our operating results and profitability. These metrics include:

inspector headcount in Pipeline Inspection;

field personnel headcount and utilization in Pipeline & Process Services;

saltwater disposal and residual oil volumes in Water Services;

operating expenses;

segment gross margin;

safety metrics;

Adjusted EBITDA;

maintenance and expansion capital expenditures; and

distributable cash flow.

Inspector Headcount

The amount of revenue we generate in our Pipeline Inspection segment depends primarily on the number of inspectors that perform services for our customers. The number of inspectors engaged on projects is driven by the type of project, prevailing market rates, the age and condition of customers' midstream pipelines, gathering systems, miscellaneous infrastructure, distribution systems, and the legal and regulatory requirements relating to the inspection and maintenance of those assets.

Field Personnel Headcount and Utilization

The amount of revenue we generate in our Pipeline & Process Services segment depends primarily on the number of field personnel that perform services for our customers and the fees that we charge for those services, which depend on the type and number of field personnel used on a particular project, the type of equipment used and the fees charged for the utilization of that equipment, and the nature and the duration of the project. The number of field personnel engaged on projects is driven by the type of project, the size and length of the pipeline being inspected, the complexity of services provided, and the utilization of our work force and equipment. The employees of the Pipeline & Process Services segment who perform work in the field are full-time employees, and therefore represent fixed costs (in contrast to the employees of the Pipeline Inspection segment who perform work in the field, most of whom only earn wages when they are performing work for a customer and whose wages are therefore primarily variable costs).

Saltwater Disposal and Residual Oil Volumes

The amount of revenue we generate in the Water Segment depends primarily on the volume of produced water and flowback water that we dispose for our customers pursuant to published or negotiated rates, as well as the volume of residual oil that we sell pursuant to rates that are determined based on the quality of the oil sold and prevailing oil prices. Most of the revenue generated from water delivered to our facilities by truck is generated pursuant to contracts that are short-term in nature. Most of the revenue generated from water delivered to our facilities by pipeline is generated pursuant to contracts that are several years in duration. The volumes of saltwater disposed at our saltwater disposal facilities are driven by water volumes generated from existing oil and natural gas wells during their useful lives and development drilling and production volumes from new wells located near our facilities. Producers' willingness to engage in new drilling is determined by a number of factors, the most important of which are the prevailing and projected prices of oil, natural gas, and natural gas liquids, the cost to drill and operate a well, the availability and cost of capital, and environmental and governmental regulations. We generally expect the level of drilling to positively correlate with long-term trends in prices of oil, natural gas, and natural gas liquids.

Approximately 5%, 7%, and 6% of our Water Services segment revenue for the years ended December 31, 2018, 2017 and 2016, respectively, was derived from sales of residual oil recovered during the saltwater treatment process. Our ability to recover residual oil is dependent upon the oil content in the saltwater we treat, which is, among other things, a function of water type, chemistry, source, and temperature. Generally, where outside temperatures are lower, oil separation is more difficult. Thus, our residual oil recovery during the winter season is lower than our recovery during the summer season. Additionally, residual oil content will decrease if, among other things, producers begin recovering higher levels of residual oil in saltwater prior to delivering such saltwater to us for treatment.

Operating Expenses

The primary components of our operating expenses include cost of services, general and administrative, and depreciation and amortization.

Costs of services. Employee or contractor-related costs and per diem expenses are the primary cost of services components in Pipeline Inspection and Pipeline & Process Services. These expenses fluctuate based on the number, type, and location of projects on which we are engaged at any given time. Repair and maintenance costs, employee-related costs, residual oil disposal costs, lease expenses, and utility expenses are the primary cost of services components in Water Services. These expenses generally remain relatively stable across broad ranges of saltwater disposal volumes but can fluctuate from period to period depending on the mix of activities performed during that period and the timing of these expenses.

General and administrative. General and administrative expenses include management and overhead payroll, general office expenses, management fees, legal fees, and other expenses.

Under our amended and restated omnibus agreement, Holdings charges us an annual administrative fee of \$4.0 million (payable in equal quarterly installments) for the provision of certain administrative services. This fee is subject to an increase by an annual amount equal to PPI plus one percent or, with the concurrence of the conflicts committee, in the event of an expansion of our operations, including through acquisitions or internal growth. This administrative fee will increase to \$4.5 million in 2019, based on the cumulative increase in the PPI since the inception of the omnibus agreement. To the extent that Holdings incurs overhead expenses in excess of our annual administrative fee that are attributable to the operations of the Partnership, these expenses are reported in our Consolidated Statements of Operations within *general and administrative* and as *contributions attributable to general partner* in our Consolidated Statement of Owners' Equity.

Included in this administrative fee are general and administrative expenses attributable to operating as a publicly traded partnership, such as expenses associated with annual and quarterly SEC reporting; tax return and Schedule K-1 preparation and distribution expenses; Sarbanes-Oxley compliance; listing on the New York Stock Exchange; independent registered public accounting firm fees; certain legal fees; investor relations, registrar, and transfer agent fees; and director compensation. Our partnership agreement provides that Holdings will determine and allocate expenses related to our operations and may provide us other services for which we will be charged fees as determined in good faith. Payments to Holdings and its affiliates following the termination of our amended and restated omnibus agreement could be substantial and could reduce the amount of cash we have available to distribute to our unitholders.

During the years ended December 31, 2017 and 2016, Holdings provided sponsor support to the Partnership by waiving certain payments of the quarterly administrative fee (in 2017, Holdings waived the fee for two of the quarters; in 2016, Holdings waived the fee for all four quarters). We reported the amount of the waived fees within *general and administrative* in our Consolidated Statements of Operations and as *contributions attributable to general partner* in our Consolidated Statement of Owners' Equity.

Depreciation, amortization and accretion. Depreciation, amortization and accretion expense primarily consists of the decrease in value of assets as a result of using the assets over their estimated useful life. Depreciation and amortization are recorded on a straight-line basis. We estimate that our assets have useful lives ranging from 3 to 39 years. The fixed assets of our Water Services segment constituted approximately 79% of the net book value of our consolidated fixed assets as of December 31, 2018.

Segment Gross Margin, Adjusted EBITDA, and Distributable Cash Flow

We view segment gross margin as one of our primary management tools, and we track this item on a regular basis, both as an absolute amount and as a percentage of revenues compared to prior periods. We also track Adjusted EBITDA, defined as net income (loss) plus interest expense, depreciation and amortization expense, income tax expense, impairments, non-cash allocated expenses, and equity-based compensation (less certain other unusual or non-recurring items). We use distributable cash flow, defined as Adjusted EBITDA less cash interest paid, cash taxes paid, maintenance capital expenditures, and cash distributions on preferred equity, as an additional measure to analyze our performance. Distributable cash flow does not reflect changes in working capital balances, which could be significant, as headcounts of the Pipeline Inspection segment vary from period to period. Adjusted EBITDA and distributable cash flow are non-GAAP, supplemental financial measures used by management and by external users of our financial statements, such as investors, lenders, and analysts, to assess:

our operating performance as compared to those of other providers of similar services, without regard to financing methods, historical cost basis, or capital structure;

the ability of our assets to generate sufficient cash flow to support our indebtedness and make distributions to our partners;

the viability of capital expenditure projects and the overall rates of return on alternative investment opportunities;

our ability to incur and service debt and fund capital expenditures; and

the viability of acquisitions and other capital expenditure projects and the rates of return on various investment opportunities.

Adjusted EBITDA and distributable cash flow are not financial measures presented in accordance with GAAP. We believe that the presentation of these non-GAAP financial measures provides useful information to investors in assessing our financial condition and results of operations. *Net income (loss)* is the GAAP measure most directly comparable to Adjusted EBITDA. The GAAP measure most directly comparable to distributable cash flow is *net cash provided by operating activities*. Our non-GAAP financial measures should not be considered as alternatives to the most directly comparable GAAP financial measures. Each of these non-GAAP financial measures has important limitations as an analytical tool because it excludes some, but not all, of the items that affect the most directly comparable GAAP financial measure. You should not consider Adjusted EBITDA or distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA and distributable cash flow may be defined differently by other companies in our industry, our definitions of these non-GAAP financial measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

For a further discussion of the non-GAAP financial measures of Adjusted EBITDA and reconciliation of that measure to their most comparable financial measures calculated and presented in accordance with GAAP, please read “*Item 6 — Selected Financial Data — Non-GAAP Financial Measures*.”

Outlook

All three of our segments generated increased revenues in 2018 relative to 2017, which reflects the recovery in the energy markets. We believe our essential midstream services are well-positioned for long-term growth, given the aging energy infrastructure in the U.S., the construction of new pipelines, and growing oil and gas production.

Revenues of our Pipeline Inspection segment increased from \$268.6 million in 2017 to \$288.1 million in 2018, an increase of 7.3%. Gross margins in this segment increased from \$26.7 million in 2017 to \$31.6 million in 2018, an increase of 18.3%. The gross margin percentage for the Pipeline Inspection segment increased from 10.0% in 2017 to 11.0% in 2018, as we continue to make progress on our goal of diversifying our revenues into higher-margin services. We finished 2018 with strong headcount (our weekly headcount averaged 1,375 inspectors in the fourth quarter of 2018, compared to 1,101 inspectors during the fourth quarter of 2017). During the fourth quarter of 2018, we began work on the largest contract award in our history, a pipeline project that is expected to continue throughout 2019.

Revenues of our Pipeline & Process Services segment increased from \$9.3 million in 2017 to \$15.0 million in 2018, an increase of 61.9%. The increase was due in part to increasing demand and in part to improved business development efforts. Gross margins in this segment increased from \$1.9 million in 2017 to \$4.3 million in 2018, an increase of 123.5%. We began 2019 with a solid project backlog and have had robust bidding activity on new projects.

Revenues of our Water Services segment increased from \$8.4 million during 2017 to \$11.9 million during 2018, an increase of 40.7%, which was partially driven by the completion of some new pipelines in 2018. Demand for this segment increased in 2018 as customer activity increased in the Bakken shale region with higher commodity prices. Gross margins in this segment increased from \$4.9 million in 2017 to \$8.1 million in 2018, an increase of 64.2%. These increases occurred despite the fact that we sold our two saltwater disposal facilities in Texas, on attractive terms, during January 2018 and May 2018, respectively, thereby exiting the Permian basin.

Our sponsor, Holdings, completed two acquisitions in the third quarter of 2018 that we believe will allow us to expand the breadth and depth of the pipeline integrity services we offer to our clients. Both transactions were asset purchases that require some repositioning before bringing them into the Partnership. Our sponsor made solid progress toward this goal on both acquisitions in the fourth quarter of 2018, and intends to offer them to the Partnership once it has accomplished certain developmental goals, most likely in early 2020 (if not sooner). These potential acquisitions would move us into several new lines of work, including water treatment, in-line inspection (“ILI”) with next-generation high resolution technology for energy companies, equipment rental (which could be converted into a service business before offering this line of business to the Partnership), and other pipeline process services including nitrogen and dehydration. Holdings’ new Lafayette facility also allows us to expand into the offshore market and positions us to better serve the Southeastern part of the country. The acquired ILI technology is also the first high definition tool capable of serving the municipal water industry’s aging mortar-lined steel pipelines used to transport drinking water that are in need of substantial maintenance, repair, and replacement. The future acquisitions of these businesses should also position us to eventually resume increasing our distributions.

Pipeline Inspection

Demand is growing for our Pipeline Inspection segment. We operate in a very large market, with more than 2,500 customer prospects who require federally and/or state-mandated inspection and integrity services. During the third quarter of 2018, we signed the largest contract in the 15-year history of TIR and began work on this project in the fourth quarter.

Our focus remains on both maintenance and integrity work on existing pipelines as well as work on new projects. With stronger commodity prices and healthier balance sheets, our existing and potential customers are investing in their businesses following a difficult two-year economic downturn in the energy industry. We continue to focus on new lines of business to serve our existing customers, including mechanical integrity and pipeline decontamination services. The majority of our clients are public, investment-grade companies with long planning cycles that lead to healthy backlogs of new long-term projects and existing pipeline networks that also require inspection and integrity services. We believe that regulatory requirements, coupled with the aging pipeline infrastructure, mean that, regardless of commodity prices, our customers will require our regulatory inspection services. However, a prolonged downturn in oil and natural gas prices could lead to a downturn in demand for our services.

Pipeline & Process Services

Brown, our 51% owned integrity services hydrotesting business, experienced a significant improvement in its utilization rates in 2018. Revenues of our Pipeline & Process Services segment increased from \$9.3 million in 2017 to \$15.0 million in 2018, an increase of 61.9%. The increase was due in part to increasing demand and in part to improved business development efforts. Gross margins in this segment increased from \$1.9 million in 2017 to \$4.3 million in 2018, an increase of 123.5%.

During the third quarter of 2018, we opened a new office in Odessa, Texas, to better serve the growing Permian basin market. In addition, we added several industry veterans to our management team in order to further enhance our image and grow the segment. In early 2019, an affiliated entity opened a new location in the Houston market that will help us take advantage of the growing market in the industry. Brown had two difficult years during the energy industry downturn, which forced us to implement aggressive measures to manage and reduce its cost structure. We believe these measures have been successful, as is evidenced by our improving operating results, and we plan to continue to focus on the potential synergies that may develop between this segment and our other business segments. In 2018, Brown worked in 11 states and obtained new business from TIR relationships. Brown continues to enjoy an excellent reputation in the industry and continues to bid on a substantial amount of new work.

Water Services

Our Water Services segment disposed of 14.8 million barrels of saltwater in 2018, which was an increase over the 12.6 million barrels disposed during 2017 (despite the sale of our Texas facilities in 2018). This increase was due in part to the completion in January 2018 of two new pipelines into one of our saltwater disposal facilities. Our average revenue per barrel increased to \$0.80 (inclusive of water disposal, oil reclamation, and management fees) in 2018, an increase over the average revenue per barrel of \$0.67 during 2017, due in part to an increase in revenues associated with the two new pipelines, higher disposal prices, and increased revenue from oil recovered during the saltwater disposal process.

Drilling activity improved dramatically following the downturn and the lows that occurred in May 2016. Per a published rig count as of February 8, 2019, the U.S. rig count totaled 1049, up 160% from its trough in May 2016, including a rig total of 58 in the Williston basin of the Bakken.

Crude oil prices increased during the first three quarters of 2018 (WTI peaked at \$76 per barrel in October 2018), and began to decrease thereafter (WTI decreased to \$45 per barrel at December 31, 2018 and was trading at \$57 per barrel at February 28, 2019). The increase in crude oil prices during the first three quarters of 2018 resulted in an increase in drilling activity in 2018. The recent decrease in prices may result in a decrease in new production activity in 2019. We continue to pursue a strategy of developing pipelines from customer producing fields into our facilities to increase the stability of our revenues.

We continue to focus on produced water and pipeline water whenever possible. During 2018, 94% of our volumes were produced water and 45% of our volumes were delivered via ten pipelines, including two that we constructed and own. We continue to focus on pipeline water opportunities to secure additional long-term volumes of produced water for the life of the oil and gas wells' production.

In July of 2017, a lightning strike at our Grassy Butte saltwater disposal facility initiated a fire that destroyed the surface storage equipment at the facility. It did not damage our pumps, electrical, housing, office, or downhole facilities. We had insurance covering the surface facilities with a reasonable deductible. We rebuilt and reopened the Grassy Butte facility in June 2018.

In January of 2018, we sold our subsidiary that owned a saltwater disposal facility in Pecos, Texas to an unrelated party for \$4.0 million of cash proceeds and a perpetual royalty interest in the future revenues of the facility. In May of 2018, we sold our subsidiary that owns a saltwater disposal facility in Orla, Texas to an unrelated party for \$8.2 million. We used the proceeds from these sales to reduce our outstanding debt.

Pacific Gas and Electric Bankruptcy

PG&E Corporation and its wholly-owned subsidiary Pacific Gas and Electric Company (collectively, “PG&E”) filed for bankruptcy protection on January 29, 2019. PG&E cited as the reason for its bankruptcy filing the fact that PG&E might become liable for paying damages to those affected by certain wildfires that occurred in 2017 and 2018. Regulators have completed investigations and have found PG&E responsible for certain of the wildfires and not responsible for others. Investigations of certain of the other wildfires are ongoing. PG&E has asserted that filing for bankruptcy protection will enable it to continue its normal operations until any liabilities associated with the wildfires can be resolved.

PG&E is a significant customer that accounted for \$43.4 million of the revenue and \$6.4 million of the gross margin of our Pipeline Inspection segment during the year ended December 31, 2018. As of December 31, 2018, the assets on our Consolidated Balance Sheet included \$10.3 million of accounts receivable from PG&E. We collected \$1.0 million of this balance in January 2019 prior to PG&E’s bankruptcy filing. We generated \$2.8 million of revenue from PG&E during the period from January 1, 2019 through January 28, 2019, bringing the total accounts receivable from PG&E to \$12.1 million as of the date of the bankruptcy filing. Our relationship with PG&E remains strong and they have advised us that they wish to continue receiving our services and that we will be paid in the normal course for services provided after the bankruptcy filing. We have continued to provide services to PG&E after the bankruptcy filing and value our business relationship. We have also been advised that PG&E continues to view us as an important and reliable vendor. Our receivables for services provided before the bankruptcy filing will need to work through the bankruptcy court process.

On January 29, 2019, PG&E filed a motion with the bankruptcy court (the “Court”) requesting that the Court grant PG&E authority to pay certain pre-petition claims to certain key suppliers. The motion did not specify to which suppliers the motion would apply, but the motion did describe the nature of the work that those suppliers perform. Once such category includes “operational integrity suppliers”, which are those that provide “essential and specialized goods and services so that [PG&E] can provide safe and reliable...natural gas service to their customers’ homes and businesses, while remaining in compliance with all applicable state and federal laws and regulations.” A second category includes “regulatory compliance vendors”, which include “entities that provide goods and services related to [PG&E’s] regulatory compliance obligations”. A third category includes “specialized and integrated vendors”. The motion states that PG&E “must obtain the services of a [specialized vendor] because state and federal laws and regulations require vendors to possess certain certifications, permits, licenses, particular knowledge, or technical ‘know-how’.” The motion states that PG&E is working to develop a final list of vendors that are subject to the motion. The motion indicates that PG&E would contact each such vendor and attempt to negotiate timely payment of a portion the pre-petition receivables owed to that vendor, in return for which the vendor would agree to continue to provide services to PG&E under the same terms that were in effect prior to the bankruptcy filing. Any pre-petition receivables not settled in this manner would continue to be subject to the claims resolution process in the bankruptcy proceeding. The Court granted this motion. Based on the nature of the services we provide to PG&E, which are mandated by state and federal requirements, which are critical to the safety of PG&E’s natural gas infrastructure, and which require specialized knowledge and certifications, we believe we could reasonably be included on the list of vendors that are subject to the order granting this motion; however, PG&E has not yet told us whether or not we are on the list of vendors that are subject to the order granting this motion. The order included a limit on the combined amount of pre-petition claims that may be paid pursuant to the order; at this time, we do not have a way to know the total amount

of the pre-petition claims asserted by all vendors that are subject to the order, or whether the combined amount of such claims exceeds the maximum amount allowed for under the order.

Also, on January 29, 2019, PG&E filed a motion with the Court requesting that the Court grant PG&E authority to pay pre-petition claims to certain suppliers that have filed or could file liens on PG&E's assets. The motion indicates that PG&E would contact each such vendor and offer to pay the vendor the pre-petition receivables owed to the vendor, in return for which the vendor would take whatever action was necessary to remove the liens. The Court granted this motion. We believe, based on the nature of the services we have provided to PG&E, that we have the right to file mechanics' liens on PG&E's natural gas distribution assets, and we have filed such liens in the approximately 40 counties in which we performed services that are subject to our pre-petition receivables. In certain counties, these liens have been perfected. Certain other counties requested more information in order to better identify the relevant assets. We are in the process of providing the information requested by each county, in order to perfect the liens in each of those counties. The motion included a limit on the combined amount of pre-petition claims that may be paid pursuant to the motion; at this time, we do not have a way to know the total amount of the pre-petition claims asserted by all vendors that are subject to the motion, or whether the combined amount of such claims exceeds the maximum amount allowed for under the motion.

We have not recorded an allowance against the accounts receivable from PG&E at December 31, 2018, as we do not believe it is probable that we will ultimately be unable to collect the full balance of the pre-petition receivables. However, due to uncertainties associated with the bankruptcy process, we cannot make assurances regarding the ultimate collection of these receivables nor can we make assurances regarding the timing of any such collections.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies and make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses. See “*Note 2 — Summary of Significant Accounting Policies*” in the audited financial statements included in “*Item 8 — Financial Statements and Supplementary Data*” for descriptions of our major accounting policies and estimates. Certain of these accounting policies and estimates 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. The following discussions of critical accounting estimates, including any related discussion of contingencies, address all important accounting areas where the nature of accounting estimates or assumptions could be material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change.

Business Combinations and Intangible Assets Including Goodwill

We account for acquisitions of businesses using the acquisition method of accounting. Accordingly, assets acquired and liabilities assumed are recorded at their estimated fair values at the acquisition date. The excess of purchase price over fair value of net assets acquired, including the amount assigned to identifiable intangible assets, is recorded as goodwill. The results of operations of acquired businesses are included in the Consolidated Financial Statements from the acquisition date.

Impairments of Long-Lived Assets

Property and Equipment

We assess property and equipment for possible impairment whenever events or changes in circumstances indicate that the carrying value of the assets may not be recoverable. Such indicators include, among others, the nature of the asset, the projected future economic benefit of the asset, changes in regulatory and political environments, and historical and future cash flow and profitability measurements. If the carrying value of an asset group exceeds the undiscounted cash flows estimated to be generated by the asset group, we recognize an impairment loss equal to the excess of carrying value of the asset group over its estimated fair value. Estimating the future cash flows and the fair value of an asset group involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation on operating expenses, and the outlook for national or regional market supply and demand for the services we provide.

For our Water Services segment, we evaluate property and equipment for impairment at the saltwater disposal facility level. Our estimates utilize judgments and assumptions such as undiscounted future cash flows, discounted future cash flows, estimated fair value of the asset group, and the current and future economic environment in which the asset is operated. Significant judgments and assumptions in these assessments include estimates of water disposal rates, disposal volumes, expected capital costs, oil and gas drilling and producing volumes in the markets served, risks associated with the different zones into which saltwater is disposed, and our estimate of an applicable discount rate commensurate with the risk of the underlying cash flow estimates.

During years ended 2017 and 2016, we identified impairment indicators at certain of our saltwater disposal facilities and reviewed the associated property and equipment for impairment. We recognized impairment charges of \$0.7 million and \$2.1 million during the years ended 2017 and 2016, respectively, for assets that were determined to be impaired, primarily driven by the dramatic decline in oil prices from over \$100 / barrel to as low as \$26 / barrel during the three-year downturn. These impairment reviews utilized inputs generally consistent with those described above. Judgments and assumptions are inherent in our estimate of future cash flows used to evaluate these assets. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the Consolidated Financial Statements.

An estimate as to the sensitivity to earnings for these periods had we used other assumptions in our impairment reviews and impairment calculations is not practicable, given the number of assumptions involved in the estimates. Favorable changes to some assumptions might have obviated the need to impair any assets in these periods, whereas unfavorable changes might have caused an additional unknown number of other assets to become impaired. Additionally, further unfavorable changes in the future are reasonably possible, and therefore, it is possible that we may incur additional impairment charges in the future.

Identifiable Intangible Assets

Our recorded net identifiable intangible assets of \$22.8 million and \$25.5 million at December 31, 2018 and 2017, respectively, consist primarily of customer relationships and trademarks and trade names, amortized on a straight-line basis over estimated useful lives ranging from 5 – 20 years. Identifiable intangible assets with finite lives are amortized on a straight-line basis over their estimated useful lives, which is the period over which the asset is expected to contribute directly or indirectly to our future cash flows. We have no indefinite-lived intangibles other than goodwill. The determination of the fair value of the intangible assets and the estimated useful lives are based on an analysis of all pertinent factors including (1) the use of widely-accepted valuation approaches, such as the income approach or the cost approach, (2) our expected use of the asset, (3) the expected useful life of related assets, (4) any legal, regulatory, or contractual provisions, including renewal or extension periods that would cause substantial costs or modifications to existing agreements, and (5) the effects of demand, competition, and other economic factors. Should any of the underlying assumptions indicate that the value of the intangible assets might be impaired, we may be required to reduce the carrying value and/or subsequent useful life of the asset. If the underlying assumptions governing the amortization of an intangible asset were later determined to have significantly changed, we may be required to adjust the amortization period of such asset to reflect any new estimate of its useful life. Any write-down of the value or unfavorable change in the useful life of an intangible asset would increase expense at that time.

In 2017, we ceased to perform certain services for the largest customer of the Canadian subsidiary of our Pipeline Inspection segment. In consideration of this, we recorded impairments to the carrying values of certain intangible assets of \$1.3 million in the first quarter of 2017. Of this amount, \$1.1 million related to customer relationships and \$0.2 million related to trade names. Based on discounted cash flow calculations, we concluded the fair value of the customer relationships and trade names of our Canadian business was zero, and therefore we impaired the full amounts.

Goodwill

At December 31, 2018 and 2017, we had \$50.3 million and \$53.4 million (plus another \$2.0 million of goodwill included in *assets held for sale*) of goodwill, respectively. Goodwill is not amortized, but is subject to annual reviews on November 1 for impairment (or at other dates if events or changes in circumstances indicate that the carrying value of goodwill may be impaired) at a reporting unit level. The reporting units are determined primarily from the manner in which the business is managed and operated. A reporting unit is an operating segment or a component that is one level below an operating segment. We have determined that the Pipeline Inspection, Pipeline & Process Services, and Water Services segments are the appropriate reporting units for testing goodwill impairment.

To perform a goodwill impairment assessment, we first evaluate qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit exceeds its carrying value. If this assessment reveals that it is

more likely than not that the carrying value of a reporting unit exceeds its fair value, we then determine the estimated fair market value of the reporting unit. If the carrying amount exceeds the reporting unit's fair value, we record a goodwill impairment charge for the excess (not exceeding the carrying value of the reporting unit's goodwill).

Our estimates of fair value are sensitive to changes in a number of variables, certain of which relate to broader macroeconomic conditions outside our control. As a result, actual performance could be different from these expectations and assumptions. This could be caused by events such as strategic decisions made in response to economic and competitive conditions and the impact of economic factors. In addition, some of the estimates and assumptions used in determining fair value of the reporting units are outside the control of management, including commodity prices, interest rates, cost of capital, and our credit ratings. The facilities of our Water Services reporting units are concentrated in one basin, and changes in oil and gas production in this basin could have a significant impact on the profitability of this reporting unit. While we believe we have made reasonable estimates and assumptions to estimate the fair values of our reporting units, it is reasonably possible that changes could occur that would require a goodwill impairment charge in the future.

Pipeline Inspection

We completed our annual goodwill impairment assessment as of November 1, 2018 and concluded the \$40.2 million of goodwill of the Pipeline Inspection segment was not impaired. Our evaluations included various qualitative factors, including current and projected earnings, current customer relationships and projects, and the impact of crude oil prices on our earnings. The qualitative assessments on this reporting unit indicated that there was no need to conduct further quantitative testing for goodwill impairment. The use of different assumptions and estimates from the assumptions and estimates we used in our qualitative analyses could have resulted in the requirement to perform quantitative goodwill impairment analyses.

Pipeline & Process Services

In the Pipeline & Process Services segment, we experienced declining revenues in 2016 due to the decline in the overall energy economy, including decreased new infrastructure construction, postponement of inspection and integrity activity by our E&P customers, and reduced revenues and margins on completed contracts due to increased competition, among other factors. Given these indicators of impairment, we performed an impairment assessment in the second quarter of 2016 of the \$10.0 million of goodwill that was attributable to our Pipeline & Process Services segment. We estimated the fair value of the reporting unit utilizing the income approach (discounted cash flows) valuation method, which is a Level 3 input as defined in ASC 820, *Fair Value Measurement*. Significant inputs in the valuation included projections of future revenues, anticipated operating costs and appropriate discount rates. To estimate the fair value of the reporting unit and the implied fair value of goodwill under a hypothetical acquisition of the reporting unit, we assumed a tax structure wherein a buyer would obtain a step-up in the tax basis of the net assets acquired. Significant assumptions used in valuing the reporting unit included revenue growth rates ranging from 2% to 5% annually and a discount rate of 17.5%. In our assessment, the carrying value of the reporting unit, including goodwill, exceeded its estimated fair value. We then determined through our hypothetical acquisition analysis that the fair value of goodwill was impaired. As a result, we recorded an impairment loss of \$8.4 million and reduced the carrying value of goodwill to \$1.6 million in the second quarter of 2016.

In the first quarter of 2017, we recorded an impairment to the remaining \$1.6 million carrying value of the goodwill of the Pipeline & Process Services segment. Revenues of this segment were lower than we had expected for the first quarter of 2017. In addition, for this segment, the level of bidding activity for work is typically high in March and April once customers have finalized their budgets for the upcoming year. While we won bids on a number of projects and our backlog began to improve, the improvement in the backlog was slower than we had originally anticipated, and we revised downward our expectations of the near-term operating results of the segment. We estimated the fair value of the Pipeline & Process Services segment utilizing the income approach (discounted cash flows) valuation method, which is a Level 3 input as defined in ASC 820, *Fair Value Measurement*. Significant inputs in the valuation included projections of future revenues, anticipated operating costs and appropriate discount rates. Significant assumptions included a 2% annual growth rate of cash flows and a discount rate of 18%. We determined through this analysis that the fair value of goodwill of the Pipeline & Process Services segment was fully impaired.

Water Services

We completed our annual goodwill impairment assessment as of November 1, 2018 and concluded that the remaining \$10.1 million of goodwill of the Water Services segment was not impaired. We performed a qualitative analysis that took into consideration current and projected earnings, current customer relationships, and the fact that we sold two of our saltwater disposal facilities in 2018 at prices that exceeded their carrying values for a combined gain of \$3.6 million, which is included in *gain on asset disposals, net* in our Consolidated Statement of Operations for the year ended December 31, 2018. Based on these qualitative considerations, we concluded that the remaining carrying value of the goodwill of the Water Services segment was not impaired.

Consolidated Results of Operations – Cypress Energy Partners, L.P.

Factors Impacting Comparability

The historical results of operations for the periods presented may not be comparable, either to each other or to our future results of operations, for reasons described below:

We recorded net gains on asset disposals of \$4.1 million in 2018.

We recorded impairments of long-lived assets totaling \$3.6 million and \$10.5 million in 2017 and 2016, respectively.

During 2017 and 2016, Holdings waived a portion of the \$4.0 million annual administrative fee that we otherwise would have owed to Holdings. During 2017, Holdings waived \$2.0 million of this administrative fee, and during 2016, Holdings waived the full \$4.0 million of the administrative fee. We reported the amount of expense incurred by Holdings but not charged to us within *general and administrative expense* in our Consolidated Statements of Operations. Such expenses incurred by Holdings but not charged to us totaled \$1.8 million in 2017 and \$3.8 million in 2016. In addition, Holdings provided us with additional financial support by making cash contributions of \$2.3 million and \$2.5 million in 2017 and 2016, respectively, as a reimbursement for certain expenditures incurred by the Partnership. These cash contributions are reflected as a component of the *net loss attributable to the general partner* in the Consolidated Statements of Operations for the years ended December 31, 2017 and 2016.

In 2018, we issued \$43.5 million of preferred equity and made net payments of \$60.8 million on our revolving credit facility.

In 2017, we began recording currency gains and losses on certain intercompany balances in our Consolidated Statements of Operations.

Consolidated Results of Operations

The following table compares the operating results of Cypress Energy Partners, L.P. for the years ended December 31:

	2018	2017 (in thousands)	2016
Revenues	\$ 314,960	\$ 286,342	\$ 297,997
Costs of services	270,914	252,739	262,517
Gross margin	44,046	33,603	35,480
Operating costs and expense:			
General and administrative	23,744	21,055	21,853
Depreciation, amortization and accretion	4,404	4,443	4,861
Impairments	—	3,598	10,530
Gain on asset disposals, net	(4,108)	(570)	—
Operating income (loss)	20,006	5,077	(1,764)
Other income (expense):			
Interest expense, net	(6,206)	(7,335)	(6,559)
Debt issuance cost write-off	(114)	—	—
Foreign currency gains (losses)	(643)	732	—
Other, net	373	199	356
Net income (loss) before income tax expense	13,416	(1,327)	(7,967)
Income tax expense	1,318	596	1,195
Net income (loss)	12,098	(1,923)	(9,162)
Net income (loss) attributable to non-controlling interests	685	(1,110)	(4,499)
Net income (loss) attributable to partners / controlling interests	11,413	(813)	(4,663)
Net loss attributable to general partner	—	(4,050)	(6,298)
Net income attributable to limited partners	11,413	3,237	1,635
Net income attributable to preferred unitholder	2,445	—	—
Net income attributable to subordinated unitholders	—	—	816
Net income attributable to common unitholders	\$ 8,968	\$ 3,237	\$ 819

See the detailed discussion of elements of operating income (loss) by reportable segment below. See also Note 13 to our Consolidated Financial Statements included in “Item 8. – Financial Statement and Supplementary Data.”

The following is a discussion of significant changes in the non-segment related corporate other income and expenses for the years ended December 31, 2018 and 2017.

Interest expense. Interest expense primarily consists of interest on borrowings under our Credit Agreement, amortization of debt issuance costs, and unused commitment fees. Changes in interest expense resulted primarily from changes in the balance of outstanding debt and to changes in interest rates. During 2018, we made net payments of \$60.8 million to reduce the balance on our revolving credit facility. The interest rate on our credit facility floats with changes in LIBOR, and LIBOR rates increased during the period from 2016 to 2018. The average debt balance outstanding and average interest rates are summarized in the table below:

Year Ended December 31,	Average Debt Balance Outstanding	Average Interest Rate
	(in thousands)	
2018	98,655	5.52%
2017	136,900	4.71%
2016	137,305	4.13%

Debt issuance cost write-off. In 2018, we entered into an amendment to our revolving credit facility and wrote off \$0.1 million of debt issuance costs, which represented the portion of the unamortized debt issuance costs attributable to lenders who are no longer participating in the credit facility subsequent to the amendment to the Credit Agreement.

Foreign currency gains (losses). Our Canadian subsidiary has certain intercompany payables to our U.S.-based subsidiaries. Such intercompany payables and receivables among our consolidated subsidiaries are eliminated in our Consolidated Balance Sheets. Beginning April 1, 2017, we report currency translation adjustments on these intercompany payables and receivables within *foreign currency gains (losses)* in our Consolidated Statements of Operations. The net foreign currency losses during 2018 resulted from the depreciation of the Canadian dollar relative to the U.S. dollar. The net foreign currency gains during 2017 resulted from the appreciation of the Canadian dollar relative to the U.S. dollar.

Other, net. Other income primarily consists of royalty income, interest income, and income associated with our 25% interest in a managed saltwater disposal facility in North Dakota, which we account for under the equity method.

Income tax expense. We qualify as a partnership for income tax purposes, and therefore, we generally do not pay income tax; instead, each owner reports his or her share of our income or loss on his or her individual tax return. Our income tax provision relates primarily to (1) our U.S. corporate subsidiaries that provide services to public utility customers, which do not appear to fit within the definition of qualified income as it is defined in the Internal Revenue Code, Regulations, and other guidance, which subjects this income to U.S. federal and state income taxes, (2) our

Canadian subsidiary, which is subject to Canadian federal and provincial income taxes, and (3) certain state income taxes, including the Texas franchise tax.

The increase in income tax expense in 2018 compared to 2017 is due to an income tax benefit recorded in 2017 related to the impairment of certain long-lived assets of our Canadian subsidiary, an increase in earnings in 2018 compared to 2017 of our taxable subsidiary in the U.S. that provides services to public utility customers, and increased franchise taxes in 2018 compared to 2017 as a result of increased business activity in Texas. These increases were partially offset by the reduction in the U.S. federal income tax rate as a result of a tax law that went into effect on January 1, 2018. The decrease in income tax expense in 2017 compared to 2016 is primarily due to tax benefits recorded in 2017 related to the impairment of certain long-lived assets of our Canadian subsidiary.

As a publicly-traded partnership, we are subject to a statutory requirement that 90% of our total gross income represent “qualifying income” (as defined by the Internal Revenue Code, related Treasury Regulations, and Internal Revenue Service pronouncements), determined on a calendar-year basis. Income generated by taxable corporate subsidiaries is excluded from this calculation. During 2018, substantially all our gross income, which consisted of \$247.1 million of revenue (exclusive of the income generated by our taxable corporate subsidiaries), represented “qualifying income”.

Net income (loss) attributable to noncontrolling interests. We own a 51% interest in Brown and a 49% interest in CF Inspection. The accounts of these subsidiaries are included within our Consolidated Financial Statements. The portion of the net income (loss) of these entities that is attributable to outside owners is reported in *net income (loss) attributable to noncontrolling interests* in our Consolidated Statements of Operations. Changes in the *net income (loss) attributable to noncontrolling interests* from 2016 to 2018 related primarily to changes in the net income generated by Brown.

Net loss attributable to general partner. The net loss attributable to general partner shown in our Consolidated Statements of Operations includes general and administrative expenses incurred by Holdings on behalf of the Partnership totaling \$1.8 million and \$3.8 million for the years ended 2017 and 2016, respectively. These represent administrative costs incurred by Holdings in excess of amounts charged to us under our omnibus agreement and are reflected as *general and administrative* in the Consolidated Statements of Operations. In addition, Holdings provided us with additional financial support by making cash contributions of \$2.3 million and \$2.5 million in 2017 and 2016, respectively, as a reimbursement for certain expenditures incurred by the Partnership. These cash contributions are reflected as a component of the *net loss attributable to the general partner* in the Consolidated Statements of the Operations for the years ended December 31, 2017 and 2016.

Net income attributable to preferred unitholder. On May 29, 2018, we issued and sold \$43.5 million of preferred equity. The holder of the preferred units is entitled to an annual return of 9.5% on this investment. This return is reported in *net income attributable to preferred unitholder* in the Consolidated Statements of Operations.

Segment Operating Results***Pipeline Inspection***

The following table summarizes the operating results of our Pipeline Inspection segment for the years ended December 31, 2018 and 2017.

	Years Ended December 31,											
	2018		% of Revenue		2017		% of Revenue		Change		% Change	
	(in thousands, except average revenue and inspector data)											
Revenues	\$ 288,083				\$ 268,635				\$ 19,448		7.2 %	
Costs of services	256,436				241,889				14,547		6.0 %	
Gross margin	31,647		11.0 %		26,746		10.0 %		4,901		18.3 %	
General and administrative	17,010		5.9 %		13,980		5.2 %		3,030		21.7 %	
Depreciation, amortization and accretion	2,237		0.8 %		2,331		0.9 %		(94)		(4.0)%	
Impairments	—				1,329		0.5 %		(1,329)		(100.0)%	
Other	(21)		0.0 %		18		0.0 %		(39)		(216.7)%	
Operating income	\$ 12,421		4.3 %		\$ 9,088		3.4 %		\$ 3,333		36.7 %	
Operating Data												
Average number of inspectors	1,214				1,145				69		6.0 %	
Average revenue per inspector per week	\$ 4,551				\$ 4,499				\$ 52		1.1 %	
Revenue variance due to number of inspectors									\$ 16,374			
Revenue variance due to average revenue per inspector									\$ 3,076			

Revenue. Revenue of the Pipeline Inspection segment increased \$19.4 million during 2018 compared to 2017 due to increases in headcount and in the average revenue billed per inspector. Average inspector headcount increased by 6.0%, from 1,145 in 2017 to 1,214 in 2018. Average revenue per inspector increased 1.1%. Fluctuations in the average revenue per inspector are routine, given that we charge different rates for different types of inspectors and different types of inspection services.

Revenue attributable to our U.S. operations increased \$41.5 million during 2018 compared to 2017, due to increased activity by our clients and increased business development efforts, including the expansion of the non-destructive examination business and the formation of our mechanical integrity service business line. To help mitigate volatility in revenues associated with new construction projects, we continue to focus on areas of inspection that are less impacted by economic conditions, such as maintenance projects and projects associated with public utility companies. Revenues of our subsidiary that serves public utility companies increased by \$13.6 million in 2018 compared to 2017. Revenues of our subsidiary that performs nondestructive examination services increased by \$4.8 million in 2018 compared to 2017. The increase in revenues of our U.S. operations was partially offset by a decrease of \$22.1 million in revenue attributable to our Canadian operations, due primarily to the fact that we ceased to perform certain services for the largest customer of our Canadian subsidiary.

Costs of services. Costs of services increased \$14.5 million during 2018 compared to 2017, consistent with the increase in revenue for the year.

Gross margin. Gross margin increased \$4.9 million during 2018 compared to 2017, an increase of 18.3%. The gross margin percentage improved to 11.0% in 2018, compared to 10.0% in 2017. The increase in gross margin percentage is due to changes in the mix of services provided. During 2018, we generated more revenue from our public utility, mechanical integrity, and nondestructive examination service lines, which typically produce higher margins. During the third quarter of 2017, we ceased to perform certain services for the largest customer of our Canadian subsidiary, which services typically produced lower margins. Also in 2018, we recognized \$0.5 million of revenue on services performed in previous years. We had constrained recognition of this revenue until the expiration of a contract provision that had given the customer the opportunity to reopen negotiation of the fee for the services.

General and administrative. General and administrative expenses increased by \$3.0 million during 2018 compared to 2017, due in part to an increase of \$1.4 million in expense associated with the administrative fee charged by Holdings that was recorded by our Pipeline Inspection segment in 2018. During 2017, Holdings waived \$1.4 million of this administrative fee. In 2018, Holdings did not provide any financial support to us. Compensation expense increased approximately \$1.0 million during 2018 due to an increase in personnel to support our growing businesses. In addition, professional fees increased by \$0.5 million, due primarily to legal costs associated with certain employment-related lawsuits and claims.

Depreciation and amortization. Depreciation and amortization expense during 2018 was similar to depreciation and amortization expense during 2017.

Impairments. In the first quarter of 2017, we ceased to perform lower-margin services for the largest customer of the Canadian subsidiary of our Pipeline Inspection segment. In consideration of this, we recorded impairments to the carrying values of certain intangible assets of \$1.3 million in the first quarter of 2017. Of this amount, \$1.1 million related to customer relationships and \$0.2 million related to trade names. Based on discounted cash flow calculations, we concluded the fair value of the customer relationships and trade names of our Canadian business was zero, and therefore we impaired the full amounts.

Operating income. Operating income increased by \$3.3 million during 2018 compared to 2017, an increase of 36.7%, due primarily to the increase in gross margin and the absence of impairment expense in 2018, partially offset by our payment of the quarterly administrative fees charged by Holdings in 2018, which fees were waived in the first two quarters of 2017, additional compensation expense, and increased professional services expense.

The following table summarizes the operating results of our Pipeline Inspection segment for the years ended December 31, 2017 and 2016.

	Years Ended December 31,					
	%		%			
	2017	2016	Change	% Change		
	of	of				
	Revenue	Revenue				
	(in thousands, except average revenue and inspector data)					
Revenues	\$ 268,635	\$ 275,171	\$ (6,536)	(2.4)%		
Costs of services	241,889	247,214	(5,325)	(2.2)%		
Gross margin	26,746	27,957	(1,211)	(4.3)%		
	10.0 %	10.2 %				

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General and administrative	13,980	5.2	%	12,521	4.6	%	1,459	11.7	%
Depreciation, amortization and accretion	2,331	0.9	%	2,439	0.9	%	(108)	(4.4)	%
Impairments	1,329	0.5	%	—			1,329		
Other	18	0.0	%	—			18		
Operating income	\$ 9,088	3.4	%	\$ 12,997	4.7	%	\$ (3,909)	(30.1)	%

Operating Data

Average number of inspectors	1,145			1,147			(2)	(0.2)	%
Average revenue per inspector per week	\$ 4,499			\$ 4,601			\$ (102)	(2.2)	%
Revenue variance due to number of inspectors							\$ (469)		
Revenue variance due to average revenue per inspector							\$ (6,067)		

Revenues. Revenues decreased approximately \$6.5 million for the year ended December 31, 2017 compared to the year ended December 31, 2016, primarily due to a reduction in the average revenue billed for each inspector (accounting for a \$6.1 million revenue decrease) and, to a lesser extent, a decrease in the average number of inspectors engaged (a decrease of 2 inspectors, accounting for \$0.5 million of the decrease). Revenues of our Canadian business decreased \$7.8 million during the year ended December 31, 2017 compared to the year ended December 31, 2016, due primarily to the fact that we ceased to perform certain services for the largest customer of our Canadian subsidiary. This decrease was partially offset by an increase of \$1.3 million in our U.S. business lines, including increases of \$1.4 million in our public utility business and \$4.4 million in our non-destructive examination service line, partially offset by a decrease of \$4.5 million in revenues of our traditional inspection services during the year ended December 31, 2017 compared to the year ended December 31, 2016.

The decline in average revenue per inspector is due to changes in customer mix. Fluctuations in the average revenue per inspector per year are expected, given that we charge different rates for different type of inspectors and different types of inspection services. Competition remains intense in the industry, which continued to exert downward pressure on rates.

Costs of services. Costs of services decreased approximately \$5.3 million during the year ended December 31, 2017 compared to the year ended December 31, 2016, consistent with lower revenues.

Gross margin. Gross margin decreased approximately \$1.2 million during the year ended December 31, 2017, due primarily to lower revenues. The gross margin percentage during the year ended December 31, 2017 was similar to that of the year ended December 31, 2016, as declines in margin percentage resulting from competitive pressures were partially offset by increased revenues in our higher-margin business lines, such as the nondestructive examination service line.

General and administrative. General and administrative expenses increased approximately \$1.5 million in the year ended December 31, 2017, compared to the year ended December 31, 2016. The increase was primarily due to the fact that Holdings charged the Pipeline Inspection segment \$1.4 million during the year ended December 31, 2017 for administrative services, as allowed for under our omnibus agreement with Holdings. During the year ended December 31, 2016, Holdings waived the full amount of this administrative fee.

Depreciation and amortization. Depreciation and amortization expense during 2017 was similar to depreciation and amortization expense during 2016.

Impairments. In the first quarter of 2017, we ceased to perform lower-margin services for the largest customer of the Canadian subsidiary of our Pipeline Inspection segment. In consideration of this, we recorded impairments to the carrying values of certain intangible assets of \$1.3 million in the first quarter of 2017. Of this amount, \$1.1 million related to customer relationships and \$0.2 million related to trade names. Based on discounted cash flow calculations, we concluded the fair value of the customer relationships and trade names of our Canadian business was zero, and therefore we impaired the full amounts.

Pipeline & Process Services

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The following table summarizes the results of the Pipeline & Process Services segment for the years ended December 31, 2018 and 2017.

	Year Ended December 31,					
	2018	%	2017	%	Change	% Change
	of Revenue		of Revenue			
	(in thousands, except average revenue and inspector data)					
Revenues	\$ 15,001		\$ 9,268		\$ 5,733	61.9 %
Costs of services	10,708		7,347		3,361	45.7 %
Gross margin	4,293	28.6 %	1,921	20.7 %	2,372	123.5 %
General and administrative	2,379	15.9 %	1,981	21.4 %	398	20.1 %
Depreciation, amortization and accretion	592	3.9 %	626	6.8 %	(34)	(5.4)%
Impairments	—		1,581	17.1 %	(1,581)	(100.0)%
Gain on asset disposals, net	(83)	(0.6)%	—	0.0 %	(83)	
Operating income/(loss)	\$ 1,405	9.4 %	\$ (2,267)	(24.5)%	\$ 3,672	(162.0)%
Operating Data						
Average number of field personnel	23		20		3	15.0 %
Average revenue per field personnel per week	\$ 12,508		\$ 8,887		\$ 3,621	40.7 %
Revenue variance due to number of field personnel					\$ 1,951	
Revenue variance due to average revenue per field personnel					\$ 3,782	

Revenue. Revenue increased \$5.7 million during 2018 compared to 2017, an increase of 61.9%. The Pipeline & Process Services segment won more bids for large projects, and as a result, employee utilization was significantly higher in 2018 than in 2017. The increase in successful bids was due to improving market conditions and to improved business development efforts. Revenue during 2018 included \$0.3 million associated with additional billings on a project that we completed in late 2017 (we recognized the revenue upon receipt of customer acknowledgment of the additional fees).

Our Pipeline & Process Services segment generates most of its revenues from a smaller number of larger-scale projects than does our Pipeline Inspection segment; as a result, the revenues of the Pipeline & Process Services segment are more volatile, and revenues for a given period of time can be significantly influenced by the ability to win a relatively small number of bids for large hydrotesting projects. During the year ended December 31, 2018, 51% of the revenues of the Pipeline & Process Services segment were generated from the 10 largest projects.

Costs of services. Cost of services increased \$3.4 million during 2018 compared to 2017, as a result of the increase in revenues.

Gross margin. Gross margin increased \$2.4 million during the 2018 compared to 2017, an increase of 123.5%. The employees of the Pipeline & Process Services segment who perform work in the field are full-time employees, and therefore represent fixed costs (in contrast to the employees of the Pipeline Inspection segment who perform work in the field, most of whom only earn wages when they are performing work for a customer and whose wages are therefore primarily variable costs). Because these employees were more fully utilized during 2018 than during 2017, the gross margin percentage was higher.

General and administrative. General and administrative expenses primarily include compensation expense for office employees and general office expenses. These expenses increased by \$0.4 million during 2018 compared to 2017 due primarily to increased compensation and business development costs.

Depreciation and amortization. Depreciation and amortization expenses include depreciation of property and equipment and amortization of intangible assets associated with customer relationships, trade names, and noncompete agreements. Depreciation and amortization expense during 2018 was similar to depreciation and amortization expense during 2017.

Impairments. During 2017, we recorded a full impairment to the goodwill of the Pipeline & Process Services reporting unit. Although we had recently won bids on a number of projects and our backlog had begun to improve, the improvement in the backlog had been slower than we had anticipated, and accordingly, we revised downward our expectations of the near-term operating results of the segment.

Operating income (loss). Operating income increased by \$3.7 million during 2018 compared to 2017. This increase was due, in part, to higher gross margins of \$2.4 million and in part to the absence of impairment expense in 2018, compared to \$1.6 million of impairment expense recorded during 2017, partially offset by increased general and administrative expense.

The following table summarizes the results of the Pipeline & Process Services segment for the years ended December 31, 2017 and 2016.

	Year Ended December 31,							
	% of			% of			Change	% Change
	2017			2016				
	Revenue			Revenue				
	(in thousands, except average revenue and inspector data)							
Revenues	\$ 9,268			\$ 13,884			\$ (4,616)	(33.2)%
Costs of services	7,347			11,542			(4,195)	(36.3)%
Gross margin	1,921	20.7 %		2,342	16.9 %		(421)	(18.0)%
General and administrative	1,981	21.4 %		2,829	20.4 %		(848)	(30.0)%
Depreciation, amortization and accretion	626	6.8 %		658	4.7 %		(32)	(4.9)%
Impairments	1,581	17.1 %		8,411	60.6 %		(6,830)	(81.2)%
Operating income	\$ (2,267)	(24.5)%		\$ (9,556)	(68.8)%		\$ 7,289	(76.3)%
Operating Data								
Average number of field personnel	20			23			(3)	(13.0)%
Average revenue per field personnel per week	\$ 8,887			\$ 11,577			\$ (2,690)	(23.2)%
Revenue variance due to number of field personnel							\$ (1,386)	
Revenue variance due to average revenue per field personnel							\$ (3,230)	

Revenue. Revenues decreased approximately \$4.6 million during the year ended December 31, 2017 compared to the year ended December 31, 2016. Revenues declined during late 2016 and early 2017, due in part to a slowdown in customer projects and to the loss during 2016 of certain business development personnel. During the second half of 2017, our revenues began to recover due to increases in customer project activity and improved business development efforts. Our Pipeline & Process Services segment generates most of its revenues from a smaller number of larger-scale projects than does our Pipeline Inspection segment; as a result, the revenues of the Pipeline & Process Services segment are more volatile, and revenues for a given period of time can be significantly influenced by the ability to win a relatively small number of bids for large hydrotesting projects.

Costs of services. Costs of services decreased approximately \$4.2 million during the year ended December 31, 2017 compared to the year ended December 31, 2016, consistent with the decrease in revenues.

Gross margin. Gross margin decreased approximately \$0.4 million during the year ended December 31, 2017 compared to the year ended December 31, 2016, primarily due to lower revenues. The employees of the Pipeline & Process Services segment who perform work in the field are full-time employees, and therefore represent fixed costs (in contrast to the employees of the Pipeline Inspection segment that perform work in the field, most of whom only earn wages when they are performing work for a customer, and whose wages are therefore variable costs). Because of this, margin percentages typically improve when revenues are higher, as our field employees are more fully utilized. The gross margin percentage was higher during the year ended December 31, 2017 than during the year ended December 31, 2016, despite the lower revenues, due to cost management measures that we implemented in response to the slowdown in activity that began during 2016.

General and administrative. General and administrative expenses consist primarily of compensation for office employees and general office expenses. These expenses decreased approximately \$0.8 million during the year ended December 31, 2017 compared to the year ended December 31, 2016, due primarily to cost-cutting measures we implemented in response to the low-revenue environment, which included reductions in office head count as well as the closure of an office location.

Depreciation and amortization. Depreciation and amortization expense includes depreciation of property and equipment and amortization of intangible assets associated with customer relationships, trade names and non-compete agreements. Depreciation and amortization expense during the year ended December 31, 2017 was similar to depreciation and amortization expense for the year ended December 31, 2016.

Impairments. During the year ended December 31, 2016, we recorded an impairment of \$8.4 million to the goodwill associated with the Pipeline & Process Services segment in response to the decline in revenues. During the year ended December 31, 2017, we recorded an additional impairment of \$1.6 million to goodwill, which represented the full remaining amount of the goodwill attributable to this segment.

Water Services

The following table summarizes the operating results of our Water Services segment for the years ended December 31, 2018 and 2017.

	Year Ended December 31,					
	% of			% of		
	2018		2017		Change	% Change
	Revenue			Revenue		
	(in thousands, except per barrel data)					
Revenues	\$ 11,876		\$ 8,439		\$ 3,437	40.7 %
Costs of services	3,770		3,503		267	7.6 %
Gross margin	8,106	68.3 %	4,936	58.5 %	3,170	64.2 %
General and administrative	3,295	27.7 %	2,451	29.0 %	844	34.4 %
Depreciation, amortization and accretion	1,575	13.3 %	1,486	17.6 %	89	6.0 %
Impairments	—		688	8.2 %	(688)	(100.0)%
Gain on asset disposals, net	(4,004)	(33.7)%	(588)	(7.0)%	(3,416)	581.0 %
Operating income	\$ 7,240	61.0 %	\$ 899	10.7 %	\$ 6,341	705.3 %
Operating Data						
Total barrels of saltwater disposed	14,782		12,588		2,194	17.4 %
Average revenue per barrel disposed (a)	\$ 0.80		\$ 0.67		\$ 0.13	19.8 %
Revenue variance due to barrels disposed					\$ 1,471	
Revenue variance due to revenue per barrel					\$ 1,966	

(a) Average revenue per barrel disposed is calculated by dividing revenues (which includes disposal revenues, residual oil sales, and management fees) by the total barrels of saltwater disposed.

Revenue. Revenue of the Water Services segment increased by \$3.4 million during 2018 compared to 2017, an increase of 40.7%, due primarily to a 17.4% increase in the volume of saltwater disposed and an increase in the average revenue per barrel disposed of 19.8%. Revenues of our North Dakota facilities increased by \$5.0 million, from \$6.8 million during 2017 to \$11.8 million during 2018, an increase of 73.5%. Volumes of our North Dakota facilities increased by 4.7 million barrels, from 9.9 million barrels 2017 to 14.6 million barrels during 2018, an increase of 47.4%. The increase in volumes was due to the completion of a pipeline system at one of our facilities in January 2018 and to increased customer activity around several of our other facilities.

Revenues of our Texas facilities decreased by \$1.5 million, from \$1.6 million during 2017 to \$0.1 million during 2018. Volumes of our Texas facilities decreased by 2.6 million barrels, from 2.7 million barrels during 2017 to 0.1 million barrels during 2018. This was due to the sale in January 2018 of our Pecos facility and the sale in May 2018 of our Orla facility. All of our remaining facilities are now located in North Dakota.

The average revenue per barrel increased during 2018 compared to 2017, due in part to increased revenues from our new pipelines, as well as pricing increases. In addition, revenues during 2018 included \$0.1 million of management fees associated with a transition services agreement related to the sale of the Pecos facility. Average revenue per barrel may begin to decrease in 2019 based on the fact that our contract with one of our customers allows for a decrease in the per-barrel rate, once the cumulative volumes delivered via two pipelines reach an amount specified in the agreement. Revenues from the sale of recovered crude oil were modestly higher in 2018 than in 2017, due primarily to higher prices. Revenues from the sale of recovered crude oil represented 5% of our revenue in 2018 and 7% of our revenue in 2017.

Costs of services. Costs of services increased by \$0.3 million during 2018 compared to 2017. A decrease of \$0.5 million in costs of services resulting from the sale of our Texas facilities was offset by an increase of \$0.4 million in chemical and utility expense, as a result of higher volumes at our North Dakota facilities, an increase of \$0.2 million in expense related to spill cleanup costs at certain facilities, and an increase of \$0.2 million in employee compensation expense.

Gross margin. Gross margin increased \$3.2 million during 2018 compared to 2017, an increase of 64.2%, due primarily to a \$3.4 million increase in revenue, partially offset by a \$0.3 million increase in cost of services.

General and administrative. General and administrative expenses include general overhead expenses such as salary costs, insurance, property taxes, royalty expenses, and other miscellaneous expenses. These expenses increased by \$0.8 million during 2018 compared to 2017. Of this increase, \$0.6 million related to the administrative fee charged by Holdings (Holdings waived this administrative fee for the six months ended June 30, 2017). In addition, general and administrative expense during 2017 were reduced by \$0.3 million upon collection of an account receivable on which we had previously recorded a valuation allowance.

Depreciation, amortization and accretion. Depreciation, amortization and accretion expense increased by \$0.1 million in 2018 compared to 2017. This was due primarily to an increase of \$0.3 million of depreciation expense related to two pipelines that we placed into service in January 2018, partially offset by a reduction of \$0.1 million in depreciation expense associated with the sale in 2018 of one of our facilities in Texas and by a reduction of \$0.1 million in amortization expense, resulting from the fact that certain of the intangible assets became fully amortized in 2018.

Impairments. In 2017, we recorded an impairment of \$0.7 million to the property, plant and equipment at one of our saltwater disposal facilities. We experienced low volumes at this facility due to competition in the area and to low levels of exploration and production activity near the facility.

Gain on asset disposals, net. During 2018, we recorded a gain of \$1.8 million on the sale of our facility in Orla, Texas and a gain of \$1.8 million on the sale of our facility in Pecos, Texas.

During 2018, we received proceeds of \$0.4 million from the settlement of litigation related to lightning strikes that occurred in 2017 at our facilities in Orla, Texas and Grassy Butte, North Dakota. This litigation related to the non-performance of certain equipment we had purchased to protect the facilities against lightning strikes.

During 2018, we collected \$0.1 million of insurance proceeds, which represented the final payment on a property damage insurance claim related to the Grassy Butte facility.

These gains were partially offset by a loss of \$0.1 million during 2018 on the abandonment of a capital expansion project.

During 2017, we recorded net gains on asset disposals of \$0.6 million related to the lightning strikes and the resultant fires at two of our facilities. We carried property damage and cleanup insurance on both facilities, and the proceeds we received on these policies were in excess of the net book value of the damaged property and the cleanup costs we incurred.

Operating income. Our Water Services segment generated operating income of \$7.2 million during 2018 compared to operating income of \$0.9 million during 2017, an increase of 705.3%. The increase in operating income was due in part to gains of \$3.6 million from the sales of our saltwater disposal facilities in Texas, an increase of \$3.2 million in the segment's gross margin, lawsuit settlement gains of \$0.4 million, and impairments of \$0.7 million recorded in 2017, partially offset by an increase of \$0.8 million in general and administrative expenses and \$0.6 million of net gains on asset disposals in 2017.

The following table summarizes the operating results of our Water Services segment for the years ended December 31, 2017 and 2016.

	Year Ended December 31,					
	% of		% of		Change	% Change
	2017	2016				
	Revenue		Revenue			
	(in thousands, except per barrel data)					
Revenues	\$ 8,439		\$ 8,942		\$ (503)	(5.6)%
Costs of services	3,503		3,761		(258)	(6.9)%
Gross margin	4,936	58.5 %	5,181	57.9 %	(245)	(4.7)%
General and administrative	2,451	29.0 %	1,866	20.9 %	585	31.4 %
Depreciation, amortization and accretion	1,486	17.6 %	1,764	19.7 %	(278)	(15.8)%
Impairments	688	8.2 %	2,119	23.7 %	(1,431)	(67.5)%
Gain on asset disposals, net	(588)	(7.0)%	—		(588)	
Operating income (loss)	\$ 899	10.7 %	\$ (568)	(6.4)%	\$ 1,467	(258.3)%
Operating Data						
Total barrels of saltwater disposed	12,588		13,307		(719)	(5.4)%
Average revenue per barrel disposed (a)	\$ 0.67		\$ 0.67		\$ (0.00)	(0.0)%
Revenue variance due to barrels disposed					\$ (483)	
Revenue variance due to revenue per barrel					\$ (20)	

(a) Average revenue per barrel disposed is calculated by dividing revenues (which includes disposal revenues, residual oil sales, and management fees) by the total barrels of saltwater disposed.

Revenue. Revenues decreased by \$0.5 million during the year ended December 31, 2017 compared to the year ended December 31, 2016. The decline was primarily due to a 5.4% decrease in the volume of saltwater disposed. The decrease in the volume of water disposed was due to in part to a lightning strike and fire at our Orla, Texas facility in January 2017 that destroyed the surface equipment. Although we soon reopened the facility using temporary equipment, the volume of water processed at this facility decreased by 1.1 million barrels during the year ended December 31, 2017 compared to the year ended December 31, 2016. The volume of water processed at our North Dakota facilities decreased by 0.4 million barrels during the year ended December 31, 2017 compared to the year ended December 31, 2016, due primarily to a July 2017 lightning strike and fire at our Grassy Butte facility, which destroyed the surface equipment. We rebuilt the Grassy Butte facility and reopened it in June 2018. These decreases in volumes were partially offset by an increase of 0.8 million barrels processed at our Pecos, Texas facility, due to increased customer activity in the area of the facility. Average revenue per barrel processed during the year ended

December 31, 2017 was similar to that of the year ended December 31, 2016. Revenues from the sale of recovered crude oil represented 7% of our revenue in 2017 and 6% of our revenue in 2016.

Costs of services. Costs of services decreased by \$0.3 million from the year ended December 31, 2017, compared to the year ended December 31, 2016, primarily due to cost reduction measures we implemented in mid-2016 in response to adverse market conditions. These measures included the temporary suspension of activity at two of our facilities and investments in automation at other facilities.

Gross margin. Gross margin decreased by \$0.2 million during the year ended December 31, 2017, compared to the year ended December 31, 2016, due to a \$0.5 million decrease in revenue which was partially offset by a \$0.3 million decrease in costs of services.

General and administrative expense. General and administrative expenses include general office overhead expenses such as salary costs, office expense, insurance, property taxes, royalty expenses, and other miscellaneous expenses. General and administrative expense during the year ended December 31, 2017 included \$0.6 million that Holdings charged the Water Services segment for administrative services, as allowed for under our omnibus agreement with Holdings. During the year ended December 31, 2016, Holdings waived the full amount of this administrative fee.

Depreciation, amortization and accretion. Depreciation, amortization and accretion expenses decreased from 2016 to 2017 primarily due to the prior impairment of equipment at various saltwater disposal facilities. As equipment is impaired, there is less asset basis to depreciate.

Impairments. In the first quarter of 2017, we recorded an impairment of \$0.7 million to the property, plant and equipment at one of our facilities in North Dakota. We experienced low volumes at this facility due to competition in the area and to low levels of production activity near the facility, and we have temporarily idled the facility. In the second quarter of 2016, we recorded an impairment of \$2.1 million to the property, plant and equipment at one of our facilities in North Dakota, due to low levels of customer activity in the area. Market conditions near this facility have since improved, and in January 2018 we completed construction of two pipelines to connect this facility to a customer's newly-developed production fields.

(Gain) loss on asset disposals. During 2017, lightning strikes and the resultant fires destroyed the surface equipment at two of our facilities. We carry property damage and cleanup insurance on both facilities, and the proceeds we received on these policies were in excess of the net book value of the damaged property and the cleanup costs we incurred.

Liquidity and Capital Resources

We anticipate making growth capital expenditures in the future, including acquiring new businesses or expanding our existing assets and offerings in our current operations. In addition, the working capital needs of the Pipeline Inspection segment are substantial, driven by payroll and per diem expenses paid to our inspectors on a weekly basis. Please read *"Risk Factors — Risks Related to Our Business — The working capital needs of the Pipeline Inspection segment are substantial"*, which could require us to seek additional financing that we may not be able to obtain on satisfactory terms, or at all. Consequently, our ability to develop and maintain sources of funds to meet our capital requirements is critical to our ability to meet our growth objectives. We expect that our future growth capital expenditures will be funded by future borrowings and the issuance of debt and equity securities. However, we may not be able to raise additional funds on desired or favorable terms or at all.

At December 31, 2018, our sources of liquidity included:

\$15.4 million of cash on our Consolidated Balance Sheet at December 31, 2018 (inclusive of cash attributable to the noncontrolling interest owners);

available borrowings under our Credit Agreement of \$13.5 million at December 31, 2018 that are limited by certain financial covenant ratios and other provisions as outlined in the Credit Agreement; and

issuance of equity and/or debt securities.

Common Unit Distributions

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash to common unitholders of record on the applicable record date.

Available cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

less, the amount of cash reserves established by our General Partner at the date of determination of available cash for the quarter to:

provide for the proper conduct of our business, which could include, but is not limited to, amounts reserved for capital expenditures, working capital and operating expenses;

comply with applicable law, and of our debt instruments or other agreements; or

provide funds for distributions to our unitholders (including our General Partner) for any one or more of the next four quarters (provided that our General Partner may not establish cash reserves for the payment of future distributions unless it determines that the establishment of reserves will not prevent us from distributing the minimum quarterly distribution on all common units and any cumulative arrearages on such common units for such quarter);

plus, if our General Partner so determines, all or a portion of cash on hand on the date of determination of available cash for the quarter, including cash on hand resulting from working capital borrowings made after the end of the quarter.

The following table summarizes the distributions on common and subordinated units declared since our initial public offering:

Payment Date	Per Unit Cash Distributions	Total Cash Distributions (a) (in thousands, except per unit data)	Total Cash Distributions to Affiliates
Total 2014 Distributions	\$ 1.104646	\$ 13,064	\$ 8,296
Total 2015 Distributions	1.625652	19,232	12,284
Total 2016 Distributions	1.625652	19,258	12,414
February 13, 2017	0.406413	4,823	3,107
May 13, 2017	0.210000	2,495	1,606
August 12, 2017	0.210000	2,495	1,607
November 14, 2017	0.210000	2,497	1,608
Total 2017 Distributions	1.036413	12,310	7,928
February 14, 2018	0.210000	2,498	1,599
May 15, 2018	0.210000	2,506	1,604
August 14, 2018	0.210000	2,506	1,604
November 14, 2018	0.210000	2,509	1,606
Total 2018 Distributions	0.840000	10,019	6,413
February 14, 2019 (b)	0.210000	2,510	1,606
Total Distributions (through February 14, 2019 since IPO)	\$ 6.442363	\$ 76,393	\$ 48,941

(a) Approximately 64.0% of the Partnership's outstanding common units at December 31, 2018 were held by affiliates.

(b) Fourth quarter 2018 distribution was declared and paid in the first quarter of 2019.

Preferred Unit Distributions

On May 29, 2018 we issued and sold in a private placement 5,769,231 Series A Preferred Units representing limited partner interests in the Partnership (the "Preferred Units") for a cash purchase price of \$7.54 per Preferred Unit, resulting in gross proceeds to the Partnership of \$43.5 million. The purchaser of the Preferred Units is entitled to receive quarterly distributions that represent an annual return of 9.5% (which amounts to \$4.1 million per year). Of this 9.5% annual return, we will be required to pay at least 2.5% in cash and will have the option to pay the remaining 7.0% in

kind (in the form of issuing additional Preferred Units) for the first twelve quarters after the initial sale of the Preferred Units. We paid the first distribution on the Preferred Units in November 2018 of \$1.4 million in cash, which represented the period from May 29, 2018 through September 30, 2018. We also paid a quarterly distribution on the Preferred Units in February 2019 of \$1.0 million in cash.

Cash Flows

The following table sets forth a summary of the net cash provided by (used in) operating, investing and financing activities for the periods identified.

	Year Ended December 31,		
	2018	2017	2016
	<i>(in thousands)</i>		
Net cash provided by operating activities	\$ 15,409	\$ 8,253	\$ 24,819
Net cash provided by (used in) investing activities	7,007	(1,041)	(1,330)
Net cash used in financing activities	(31,466)	(10,150)	(21,289)
Effect of exchange rates on cash	(17)	753	343
Net increase (decrease) in cash and cash equivalents	\$ (9,067)	\$ (2,185)	\$ 2,543

Operating activities. During the year ended December 31, 2018, we generated operating cash flows of \$15.4 million. Prior to consideration of changes in working capital, operating cash flows during the year ended December 31, 2018 were \$16.0 million, consisting of net income of \$12.1 million plus non-operating-cash expenses of \$3.9 million (non-cash expenses include depreciation and amortization, equity-based compensation, foreign currency gains/losses, and gains/losses on the sale or impairment of assets, among others). During the year ended December 31, 2018, changes in working capital reduced operating cash flows by \$0.6 million. During periods of revenue growth, changes in working capital typically reduce operating cash flows, based on the fact that we pay our employees before we collect our accounts receivable from our customers.

During the year ended December 31, 2017, we generated operating cash flows of \$8.3 million. Prior to consideration of changes in working capital, operating cash flows during the year ended December 31, 2017 were \$8.9 million, consisting of a net loss of \$1.9 million plus non-operating-cash expenses of \$10.8 million (non-cash expenses include depreciation and amortization, equity-based compensation, foreign currency gains/losses, and gains/losses on the sale or impairment of assets, among others). Non-cash expenses included \$1.8 million expense that was incurred by Holdings for our benefit but not charged to us. During the year ended December 31, 2017, changes in working capital reduced operating cash flows by \$0.6 million. During periods of revenue growth, changes in working capital typically reduce operating cash flows, based on the fact that we pay our employees before we collect our accounts receivable from our customers.

During the year ended December 31, 2016, we generated operating cash flows of \$24.8 million. Prior to consideration of changes in working capital, operating cash flows during the year ended December 31, 2016 were \$12.5 million, consisting of a net loss of \$9.2 million plus non-operating-cash expenses of \$21.6 million (non-cash expenses include depreciation and amortization, equity-based compensation, and losses on the impairment of assets, among others). Non-cash expenses included \$3.8 million expense that was incurred by Holdings for our benefit but not charged to us. During the year ended December 31, 2016, changes in working capital increased operating cash flows by \$12.4 million. During periods of revenue growth, changes in working capital typically reduce operating cash flows, based on the fact that we pay our employees before we collect our accounts receivable from our customers; during periods of declining revenues, operating cash flows benefit from the collection of receivables earned in prior periods.

Investing activities. During the year ended December 31, 2018, cash inflows from investing activities included proceeds of \$12.2 million related to the sales of our two saltwater disposal facilities in Texas, \$0.4 million related to the settlement of litigation related to lightning strikes at two of our facilities, and \$0.1 million of property damage insurance proceeds related to the lightning strikes. Cash outflows from investing activities for the year ended December 31, 2018 included \$5.8 million of capital expenditures, which related primarily to the construction of two pipelines into one of our facilities in North Dakota, the rebuilding of the Orla, Texas facility prior to its sale, and the rebuilding of the Grassy Butte, North Dakota facility (the surface equipment at both the Orla and Grassy Butte facilities were destroyed by fires in 2017 resulting from lightning strikes). Capital expenditures also included the purchase of equipment to support the growth in our Pipeline Inspection segment's non-destructive examination business.

During the years ended December 31, 2017 and 2016, cash outflows for investing activities consisted of capital expenditures of \$3.3 million and \$1.4 million, respectively. Capital expenditures during the year ended December 31, 2017 included the construction of two pipelines to connect one of our saltwater disposal facilities in North Dakota to a customer's production fields. The remaining capital expenditures consisted primarily of equipment purchases, much of which was in support of increasing revenues in the Pipeline Inspection segment's non-destructive examination business. Cash inflows from investing activities during the year ended December 31, 2017 included \$2.3 million of proceeds on property damage insurance claims, which resulted from lightning strikes and resultant fires at two of our saltwater disposal facilities.

Financing activities. During the year ended December 31, 2018, cash inflows from financing activities included \$43.3 million of proceeds from the sale of preferred units, net of related costs. Cash outflows from financing activities included \$60.8 million of net payments to reduce the balance outstanding on our revolving credit facility. In May 2018 we completed a refinancing of our revolving credit agreement; as part of this refinancing, we significantly reduced the balance of debt outstanding using proceeds from the sale of preferred equity, proceeds from the sale of two of our saltwater disposal facilities, and cash on hand. Cash outflows from financing activities also included \$1.3 million of debt issuance costs related to the amendment to our revolving credit facility, \$10.0 million of distributions to common unitholders, \$1.4 million of distributions to preferred unitholders, and \$1.0 million of distributions to noncontrolling interests.

During the year ended December 31, 2017, cash outflows from financing activities included \$12.3 million of distributions to common and subordinated unitholders. Cash inflows from financing activities for the year ended December 31, 2017 included \$2.3 million of contributions from Holdings to support the Partnership.

During the year ended December 31, 2016 cash outflows from financing activities included \$19.7 million of distributions to owners (\$19.3 million of which was paid to common and subordinated unitholders and \$0.4 million of which was paid to noncontrolling interest owners) and \$4.0 million of repayments on the revolving credit facility. Cash inflows from financing activities for the year ended December 31, 2016 included \$2.5 million of contributions from Holdings to support the Partnership.

Working Capital

Our working capital (defined as net current assets less net current liabilities) was \$43.6 million at December 31, 2018. Our Pipeline Inspection and Pipeline & Process Services segments have substantial working capital needs as they generally pay their inspectors and field personnel on a weekly basis, but typically receive payment from their customers 45 to 90 days after the services have been performed. Please read “*Risk Factors — Risks Related to Our Business — The working capital needs of the Pipeline Inspection segment are substantial, which could require us to seek additional financing that we may not be able to obtain on satisfactory terms, or at all.*”

As described above under “*Outlook*” above, we have accounts receivable of \$12.1 million at January 29, 2019 from PG&E that now represents a pre-petition claim in PG&E’s bankruptcy filing. Although we do not believe it is probable that we will ultimately be unable to collect the full amount of these pre-petition receivables, the timing of collection of these receivables is unknown. We believe that we have sufficient liquidity, in the form of cash on hand and available capacity on our revolving credit facility, to meet our working capital needs while the PG&E bankruptcy process runs its course. However, the delay in collecting these receivables will require us to maintain a larger outstanding debt balance on the revolving credit facility than otherwise would have been required and will leave us with less flexibility to pursue growth opportunities than we otherwise would have enjoyed.

Capital Requirements

We generally have small capital expenditure requirements compared to many other master limited partnerships. Our Water Services Segment has minimal capital expenditure requirements for the maintenance of existing saltwater disposal facilities and the acquisition or construction and development of new saltwater disposal facilities. Our Pipeline Inspection segment does not generally require significant capital expenditures, other than in the nondestructive examination service line, which has invested growth capital to acquire field equipment to support its growing revenues. Our Pipeline & Process Services segment has both maintenance and growth capital needs for heavy equipment and vehicles in order to perform hydrostatic testing and other integrity procedures. Our partnership agreement requires that we categorize our capital expenditures as either maintenance capital expenditures or expansion capital expenditures.

Maintenance capital expenditures are those cash expenditures that will enable us to maintain our operating capacity or operating income over the long-term. Maintenance capital expenditures include expenditures to maintain equipment reliability, integrity, and safety, as well as to address environmental laws and regulations. Maintenance capital expenditures were \$0.7 million, \$0.5 million, and \$0.5 million for the years ended December 31, 2018, 2017, and 2016, respectively.

Expansion capital expenditures are those capital expenditures that we expect will increase our operating capacity or operating income over the long-term. Expansion capital expenditures include the acquisition of assets or businesses and the construction or development of additional saltwater disposal capacity, to the extent such expenditures are expected to expand our long-term operating capacity or operating income. Expansion capital expenditures were \$5.1 million, \$2.8 million, and \$0.9 million for the years ended December 31, 2018, 2017, and 2016, respectively. Expansion capital expenditures during 2018 related primarily to the construction of two pipelines at one of our facilities in North Dakota, the rebuilding of the Orla, Texas facility prior to its sale, and the rebuilding of the Grassy Butte, North Dakota facility (the surface equipment at both the Orla and Grassy Butte facilities were destroyed by fires in 2017 resulting from lightning strikes). Expansion capital expenditures during 2018 also included the purchase of non-destructive examination equipment for our inspection business. Capital expenditures during the year ended December 31, 2017 included \$1.9 million for the construction of the two pipelines that were completed in 2018. The first phase of this system, consisting of two pipelines, was completed in January 2018. The remaining capital expenditures during the year ended December 31, 2017 consisted primarily of equipment purchases, much of which was in support of increasing revenues in TIR's non-destructive examination business. Capital expenditures during 2016 consisted primarily of equipment purchases, much of which was in support of increasing revenues in TIR's nondestructive examination business.

Future expansion capital expenditures may vary significantly from period to period based on the investment opportunities available. We expect to fund future capital expenditures from cash flows generated from our operations, borrowings under our Credit Agreement, the issuance of additional partnership units, or debt offerings.

Credit Agreement

On May 29, 2018, we entered into an amended and restated credit agreement (as amended and restated, the "Credit Agreement") that provides up to \$90.0 million in borrowing capacity, subject to certain limitations, and contains an accordion feature that allows us to increase the borrowing capacity to \$110.0 million if the lenders agree to increase their commitments in the future or if other lenders join the facility. The three-year Credit Agreement matures May 29, 2021. The obligations under the Credit Agreement are secured by a first priority lien on substantially all of our assets. The credit agreement as it existed prior to the May 29, 2018 amendment will hereinafter be referred to as the "Previous Credit Agreement" or, together with the Credit Agreement, as the "Credit Agreements".

Outstanding borrowings at December 31, 2018 were \$76.1 million and are reflected as *long-term debt* on the Consolidated Balance Sheets beginning May 29, 2018. Outstanding borrowings at December 31, 2017 were \$136.9 million and are reflected net of debt issuance costs of \$0.6 million as *current portion of long-term debt* on the Consolidated Balance Sheets. At December 31, 2017, the outstanding balance was classified as current since the facility was scheduled to mature within one year.

All borrowings under the Credit Agreement bear interest, at our option, on a leveraged based grid pricing at (i) a base rate plus a margin of 1.5% to 3.0% per annum (“Base Rate Borrowing”) or (ii) an adjusted LIBOR rate plus a margin of 2.5% to 4.0% per annum (“LIBOR Borrowings”). The applicable margin is determined based on the leverage ratio of the Partnership, as defined in the Credit Agreement. Generally, the interest rate on our borrowings ranged from 5.15% to 6.02% for the period from May 29, 2018 to December 31, 2018. The interest rate in effect at December 31, 2018 was 6.02%. Interest on Base Rate Borrowings is payable monthly. Interest on LIBOR Borrowings is paid upon maturity of the underlying LIBOR contract, but no less often than quarterly. Commitment fees are charged at a rate of 0.50% on any unused credit and are payable quarterly. The average debt balance outstanding during the period from May 29, 2018 to December 31, 2018 was \$76.5 million.

The Credit Agreement contains various customary covenants and restrictive provisions. The Credit Agreement also requires maintenance of certain financial covenants, including a leverage ratio (as defined in the Credit Agreement) of not more than 4.0 to 1.0 and an interest coverage ratio (as defined in the Credit Agreement) of not less than 3.0 to 1.0. At December 31, 2018, our leverage ratio was 3.3 to 1.0 and our interest coverage ratio was 5.1 to 1.0, pursuant to the Credit Agreement. Upon the occurrence and during the continuation of an event of default, subject to the terms and conditions of the Credit Agreement, the lenders may declare any outstanding principal, together with any accrued and unpaid interest, to be immediately due and payable and may exercise the other remedies set forth or referred to in the Credit Agreement. We were in compliance with all debt covenants as of December 31, 2018.

In addition, the Credit Agreement restricts our ability to make distributions on, or redeem or repurchase, our equity interests, with certain exceptions detailed in the Credit Agreement. However, we may make distributions of available cash so long as, both at the time of the distribution and after giving effect to the distribution, no default exists under the Credit Agreement, we are in compliance with the financial covenants in the Credit Agreement, and we have at least \$5.0 million of unused capacity on the Credit Agreement at the time of the distribution.

Capital Leases

During 2018, our Pipeline & Process Services and Water Services segments leased vehicles for \$0.3 million under lease agreements at interest rates of 6.16% that are classified as capital leases. The leased vehicles are amortized on a straight-line basis over the lease terms of four years. Minimum lease payments related to the vehicles will be \$0.1 million for the years ending December 31, 2019 through 2021. In addition, during 2018, we entered into a lease

agreement for office copiers at interest rates of 6.49% that are classified as capital leases. The leased office copiers are amortized on a straight-line basis over the lease terms of approximately four years. Minimum lease payments related to the office copiers will be less than \$0.1 million for the years ending December 31, 2019 through 2022. The \$0.4 million capital lease obligation is reflected in the Consolidated Balance Sheets at December 31, 2018 in *property and equipment* (\$0.4 million), *accrued payroll and other* (\$0.1 million) and *other non-current liabilities* (\$0.3 million).

Off-Balance Sheet Arrangements

We do not have any off-balance sheet or hedging arrangements.

Contractual Obligations

A summary of our contractual obligations and other commitments as of December 31, 2018 is shown in the table below.

		Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
Long-term debt	(a)	\$ 76,129	\$ —	\$ 76,129	\$ —	\$ —
Interest payments on long-term debt	(b)	11,169	4,636	6,533	—	—
Operating lease obligations	(c)	4,200	762	1,359	1,358	721
Capital lease obligations	(d)	385	117	220	48	—
New system implementation	(e)	3,782	2,030	909	843	—
Asset Retirement Obligations	(f)	143	—	—	—	143
Total		\$ 95,808	\$ 7,545	\$ 85,150	\$ 2,249	\$ 864

(a) See Note 6 to our Consolidated Financial Statements for additional information on our Credit Agreement.

(b) The estimated interest payments on our long-term debt are based on the interest rate as of December 31, 2018 and borrowings outstanding at December 31, 2018. See Note 6 to our Consolidated Financial Statements for additional information on our Credit Agreement.

(c) We can exit our headquarters office building which represents approximately \$3.8 million of the operating lease obligations after 18 months (the original lease term is 84 months) with the payment of a penalty. See Note 12 to our Consolidated Financial Statements for additional information on our operating lease obligations.

(d) See Note 12 to our Consolidated Financial Statements for additional information on our capital lease obligations.

(e) During 2018, we signed agreements with a software provider and with a system integration advisor under which we will implement a new software system for payroll and human resources management. Amounts in this table include the cost of licensing the software for five years, the cost of the system integration advisor, and the cost to license our existing software until the implementation of the new system is completed.

(f) Amounts represent estimated costs related to future saltwater disposal well abandonments, net of any future accretion.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in oil, natural gas, and NGL prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. None of our market risk sensitive instruments were entered into for speculative trading purposes.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of crude oil in Water Services. Both our profitability and our cash flow are affected by volatility in the prices of crude oil. Crude oil prices are impacted by changes in the supply and demand, as well as market uncertainty. For a discussion of the volatility of crude oil prices, please read “*Risk Factors*.” Adverse effects on our cash flow from reductions in crude oil prices could adversely affect our ability to make cash distributions to unitholders. We do not hedge our exposure to crude oil prices.

Approximately 0.2% of our consolidated revenues in 2018 and 2017 were derived from sales of commodities. A hypothetical change in commodity prices of 10% would result in an increase or decrease of our revenues derived from sales of commodities by approximately \$0.1 million. Increases or decreases in commodity prices can also result in changes in demand for our wastewater disposal and pipeline inspection and integrity services, resulting in an increase or decrease of our revenues and gross margins.

Interest Rate Risk

We currently have exposure to changes in interest rates on our indebtedness associated with our Credit Agreement. We may implement swap or cap structures to mitigate our exposure to interest rate risk; however, we do not currently have any swaps or cap structures in place. Accordingly, our exposure consists of floating interest rate fluctuations on our outstanding indebtedness under our Credit Agreement of \$76.1 million as of December 31, 2018 and \$136.9 million as of December 31, 2017. A hypothetical change in interest rates of 1.0% would have resulted in an increase or decrease in our annual interest expense by approximately \$1.0 million and \$1.4 million for the years ended December 31, 2018 and 2017, respectively.

The credit markets have recently experienced historical lows in interest rates. As the overall economy strengthens, it is possible that monetary policy will continue to tighten further, resulting in higher interest rates to counter possible inflation as has been evidenced by recent interest rate hikes by the Federal Reserve. Interest rates on floating rate credit facilities and future debt offerings could be higher than current levels, causing our financing costs to increase accordingly.

Counterparty and Customer Credit Risk

Our credit exposure generally relates to receivables for services provided. If any significant customer of ours should have credit or financial problems resulting in a delay or failure to repay the amounts they owe to us, this could have a material adverse effect on our business, financial condition, results of operations or cash flows.

As described in more detail above under “Outlook”, our customer PG&E filed for bankruptcy protection on January 29, 2019. As of January 29, 2019, we had accounts receivable of \$12.1 million from PG&E. We do not believe it is probable that we will ultimately be unable to collect the full amount of these accounts receivable, although the timing of collection is uncertain at this time.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The following information is included in this Item 8:

<u>Report of Independent Registered Public Accounting Firm</u>	Page 89
<u>Consolidated Balance Sheets as of December 31, 2018 and 2017</u>	Page 90
<u>Consolidated Statements of Operations for the years ended December 31, 2018, 2017 and 2016</u>	Page 91
<u>Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2018, 2017 and 2016</u>	Page 92
<u>Consolidated Statement of Owners' Equity for the years ended December 31, 2018, 2017 and 2016</u>	Page 93
<u>Consolidated Statements of Cash Flows for the years ended December 31, 2018, 2017 and 2016</u>	Page 94
<u>Notes to Consolidated Financial Statements</u>	Page 95

Report of Independent Registered Public Accounting Firm

To the Limited Partners of Cypress Energy Partners, L.P.
and the Board of Directors of Cypress Energy Partners, GP, LLC,
General Partner of Cypress Energy Partners, L.P.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Cypress Energy Partners, L.P. (the “Partnership”) as of December 31, 2018 and 2017, and the related consolidated statements of operations, comprehensive income (loss), owners’ equity and cash flows for each of the three years in the period ended December 31, 2018, and 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 at December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

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 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, and evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Partnership's auditor since 2012.

Tulsa, Oklahoma

March 18, 2019

CYPRESS ENERGY PARTNERS, L.P.**Consolidated Balance Sheets****As of December 31, 2018 and 2017***(in thousands, except unit data)*

	December 31, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 15,380	\$ 24,508
Trade accounts receivable, net	48,789	41,693
Prepaid expenses and other	1,396	2,294
Assets held for sale	—	2,172
Total current assets	65,565	70,667
Property and equipment:		
Property and equipment, at cost	23,988	22,700
Less: Accumulated depreciation	11,266	9,312
Total property and equipment, net	12,722	13,388
Intangible assets, net	22,759	25,477
Goodwill	50,294	53,435
Debt issuance costs, net	1,260	—
Other assets	253	236
Total assets	\$ 152,853	\$ 163,203
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable	\$ 4,848	\$ 3,757
Accounts payable - affiliates	4,060	3,173
Accrued payroll and other	12,366	9,109
Liabilities held for sale	—	97
Income taxes payable	737	646
Current portion of long-term debt	—	136,293
Total current liabilities	22,011	153,075
Long-term debt	76,129	—
Other non-current liabilities	426	143
Total liabilities	98,566	153,218

Commitments and contingencies - Note 12

Owners' equity:

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Partners' capital:

Common units (11,946,901 and 11,889,958 units outstanding at December 31, 2018 and 2017, respectively)	34,677	34,614
Preferred units (5,769,231 units outstanding at December 31, 2018)	44,291	—
General partner	(25,876)	(25,876)
Accumulated other comprehensive loss	(2,414)	(2,677)
Total partners' capital	50,678	6,061
Non-controlling interests	3,609	3,924
Total owners' equity	54,287	9,985
Total liabilities and owners' equity	\$ 152,853	\$ 163,203

See accompanying notes.

CYPRESS ENERGY PARTNERS, L.P.**Consolidated Statements of Operations****For the Years Ended December 31, 2018, 2017 and 2016***(in thousands, except per unit data)*

	2018	2017	2016
Revenues	\$ 314,960	\$ 286,342	\$ 297,997
Costs of services	270,914	252,739	262,517
Gross margin	44,046	33,603	35,480
Operating costs and expense:			
General and administrative	23,744	21,055	21,853
Depreciation, amortization and accretion	4,404	4,443	4,861
Impairments	—	3,598	10,530
Gain on asset disposals, net	(4,108)	(570)	—
Operating income (loss)	20,006	5,077	(1,764)
Other income (expense):			
Interest expense, net	(6,206)	(7,335)	(6,559)
Debt issuance cost write-off	(114)	—	—
Foreign currency gains (losses)	(643)	732	—
Other, net	373	199	356
Net income (loss) before income tax expense	13,416	(1,327)	(7,967)
Income tax expense	1,318	596	1,195
Net income (loss)	12,098	(1,923)	(9,162)
Net income (loss) attributable to non-controlling interests	685	(1,110)	(4,499)
Net income (loss) attributable to partners / controlling interests	11,413	(813)	(4,663)
Net loss attributable to general partner	—	(4,050)	(6,298)
Net income attributable to limited partners	11,413	3,237	1,635
Net income attributable to preferred unitholder	2,445	—	—
Net income attributable to subordinated unitholders	—	—	816
Net income attributable to common unitholders	\$ 8,968	\$ 3,237	\$ 819
Net income per common limited partner unit:			
Basic	\$ 0.75	\$ 0.29	\$ 0.14
Diluted	\$ 0.72	\$ 0.29	\$ 0.13
Net income per subordinated limited partner unit - basic and diluted	\$ —	\$ —	\$ 0.14

Weighted average common units outstanding:			
Basic	11,929	11,152	5,934
Diluted	15,757	11,253	6,090
Weighted average subordinated units outstanding - basic and diluted	—	729	5,913

See accompanying notes.

CYPRESS ENERGY PARTNERS, L.P.

Consolidated Statements of Comprehensive Income (Loss)

For the Years Ended December 31, 2018, 2017 and 2016

(in thousands)

	2018	2017	2016
Net income (loss)	\$ 12,098	\$ (1,923)	\$ (9,162)
Other comprehensive income (loss) - foreign currency translation	263	(139)	253
Comprehensive income (loss)	\$ 12,361	\$ (2,062)	\$ (8,909)
Comprehensive income attributable to preferred unitholders	2,445	—	—
Comprehensive income (loss) attributable to non-controlling interests	685	(1,110)	(4,499)
Comprehensive loss attributable to general partner	—	(4,050)	(6,298)
Comprehensive income attributable to common and subordinated unitholders	\$ 9,231	\$ 3,098	\$ 1,888

See accompanying notes.

CYPRESS ENERGY PARTNERS, L.P.**Consolidated Statement of Owners' Equity****For the Years Ended December 31, 2018, 2017 and 2016***(in thousands)*

	Common Units	Preferred Units	General Partner	Subordinated Units	Accumulated Other Comprehensive Gain (Loss)	Non-controlling Interests	Total Owners' Equity
Owners' equity at December 31, 2015	\$ 253	\$ —	\$ (25,876)	\$ 59,143	\$ (2,791)	\$ 9,973	\$ 40,702
Net income (loss)	819	—	(6,298)	816	—	(4,499)	(9,162)
Foreign currency translation adjustment	—	—	—	—	253	—	253
Contributions attributable to General Partner	—	—	6,298	—	—	—	6,298
Distributions	(9,646)	—	—	(9,612)	—	(424)	(19,682)
Equity-based compensation	959	—	—	127	—	—	1,086
Taxes paid related to net share settlement of equity-based compensation	(107)	—	—	—	—	—	(107)
Owners' equity at December 31, 2016	(7,722)	—	(25,876)	50,474	(2,538)	5,050	19,388
Net income (loss)	3,237	—	(4,050)	—	—	(1,110)	(1,923)

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Foreign currency translation adjustment	—	—	—	—	(139)	—	(139)
Contributions attributable to General Partner	—	—	4,050	—	—	—	4,050
Distributions	(9,905)	—	—	(2,405)	—	(16)	(12,326)
Conversion of Subordinated Units to Common Units	48,111	—	—	(48,111)	—	—	—
Equity-based compensation	1,017	—	—	42	—	—	1,059
Taxes paid related to net share settlement of equity-based compensation	(124)	—	—	—	—	—	(124)
Owners' equity at December 31, 2017	34,614	—	(25,876)	—	(2,677)	3,924	9,985
Net income	8,968	2,445	—	—	—	685	12,098
Issuance of preferred units, net	—	43,258	—	—	—	—	43,258
Foreign currency translation adjustment	—	—	—	—	263	—	263
Distributions	(10,019)	(1,412)	—	—	—	(1,000)	(12,431)
Equity-based compensation	1,247	—	—	—	—	—	1,247
Taxes paid related to net share settlement of equity-based compensation	(133)	—	—	—	—	—	(133)
Owners' equity at December 31, 2018	\$ 34,677	\$ 44,291	\$ (25,876)	\$ —	\$ (2,414)	\$ 3,609	\$ 54,287

See accompanying notes.

CYPRESS ENERGY PARTNERS, L.P.**Consolidated Statements of Cash Flows****For the Years Ended December 31, 2018, 2017 and 2016***(in thousands)*

	2018	2017	2016
Operating activities:			
Net income (loss)	\$ 12,098	\$ (1,923)	\$ (9,162)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, amortization and accretion	5,480	5,544	5,788
Impairments	—	3,598	10,530
(Gain) loss on asset disposals, net	(4,108)	(570)	(19)
Interest expense from debt issuance cost amortization	560	594	570
Debt issuance cost write-off	114	—	—
Equity-based compensation expense	1,247	1,059	1,086
Equity in earnings of investee	(217)	(149)	(309)
Distributions from investee	175	75	200
Deferred tax (expense) benefit, net	51	(372)	(24)
Non-cash allocated expenses	—	1,750	3,798
Foreign currency (gains) losses	643	(732)	—
Changes in assets and liabilities:			
Trade accounts receivable	(7,165)	(3,406)	9,871
Prepaid expenses and other	1,004	(1,321)	1,350
Accounts payable and accrued payroll and other	5,440	4,471	478
Income taxes payable	87	(365)	662
Net cash provided by operating activities	15,409	8,253	24,819
Investing activities:			
Proceeds from fixed asset disposals, including insurance proceeds	12,769	2,304	46
Purchases of property and equipment	(5,762)	(3,345)	(1,376)
Net cash provided by (used in) investing activities	7,007	(1,041)	(1,330)
Financing activities:			
Issuance of preferred units, net of issuance costs	43,258	—	—
Borrowings on credit facility	2,500	—	—
Payments on credit facility	(63,271)	—	(4,000)
Debt issuance cost payments	(1,327)	—	—
Taxes paid related to net share settlement of equity-based compensation	(133)	(124)	(107)
Contributions from general partner	—	2,300	2,500
Capital lease repayments	(62)	—	—
Distributions	(12,431)	(12,326)	(19,682)

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Net cash used in financing activities	(31,466)	(10,150)	(21,289)
Effect of exchange rates on cash	(17)	753	343
Net increase (decrease) in cash and cash equivalents	(9,067)	(2,185)	2,543
Cash and cash equivalents, beginning of period (includes restricted cash equivalents of \$490 at December 31, 2017, 2016 and 2015)	24,998	27,183	24,640
Cash and cash equivalents, end of period (includes restricted cash equivalents of \$551 at December 31, 2018 and \$490 at December 31, 2017 and 2016)	\$ 15,931	\$ 24,998	\$ 27,183
Non-cash items:			
Accounts payable excluded from capital expenditures	\$ 25	\$ 567	\$ —
Acquisitions of property and equipment included in liabilities	400	—	—
Supplemental cash flow disclosures:			
Cash taxes paid	\$ 1,174	\$ 1,350	\$ 551
Cash interest paid	5,781	6,842	5,859

See accompanying notes.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements

1. Organization and Operations

Cypress Energy Partners, L.P. (“we”, “us”, “our”, or the “Partnership”) is a Delaware limited partnership formed in 2013 to provide independent pipeline inspection and integrity services to producers, public utility companies, and pipeline companies and to provide saltwater disposal and other water and environmental services to U.S. onshore oil and natural gas producers and trucking companies. Trading of our common units began January 15, 2014 on the New York Stock Exchange under the symbol “CELP”. Our business is organized into the Pipeline Inspection Services (“Pipeline Inspection”), Pipeline & Process Services (“Pipeline & Process Services”), and Water and Environmental Services (“Water Services”) segments.

The Pipeline Inspection segment generates revenue primarily by providing essential inspection and integrity services on a variety of infrastructure assets including midstream pipelines, gathering systems, and distribution systems. Services include non-destructive examination, mechanical integrity, in-line inspection support, pig tracking, survey, data gathering, and supervision of third-party contractors. Our results in this segment are driven primarily by the number of inspectors that perform services for our customers and the fees that we charge for those services, which depend on the type, skills, technology, equipment, and number of inspectors used on a particular project, the nature of the project, and the duration of the project. The number of inspectors engaged on projects is driven by the type of project, prevailing market rates, the age and condition of customers’ assets including pipelines, gas plants, compression stations, storage facilities, and gathering and distribution systems including the legal and regulatory requirements relating to the inspection and maintenance of those assets. Our customers are also billed for per diem charges, mileage, and other reimbursement items. Revenue and costs in this segment may be subject to seasonal variations and interim activity may not be indicative of yearly activity, considering many of our customers develop yearly operating budgets and enter into contracts with us during the winter season for work to be performed during the remainder of the year. Additionally, inspection work throughout the United States during the winter months (especially in the northern states) may be hampered or delayed due to inclement weather, thus affecting our revenue and costs.

The Pipeline & Process Services segment (formerly our Integrity Services segment) generates revenue primarily by providing essential midstream services including hydrostatic testing services and chemical cleaning to energy companies and pipeline construction companies of newly-constructed and existing pipelines and related infrastructure. We generally charge our customers in this segment on a fixed-bid basis, depending on the size and length of the pipeline being tested, the complexity of services provided, and the utilization of our work force and equipment. Our results in this segment are driven primarily by the number of field personnel that perform services for our customers and the fees that we charge for those services, which depend on the type and number of field personnel used on a particular project, the type of equipment used and the fees charged for the utilization of that equipment, and the nature and duration of the project.

The Water Services segment owns and operates nine (9) Environmental Protection Agency Class II saltwater disposal facilities in the Williston Basin region of North Dakota. Eight (8) of the facilities are wholly-owned and we have ten (10) pipelines from multiple E&P customers connected to these saltwater disposal facilities, including two (2) that were developed and are owned by the Partnership. Our saltwater disposal facilities provide essential midstream services to oil and natural gas upstream producers and their transportation companies. All of the saltwater disposal facilities utilize specialized equipment and remote monitoring to minimize the facilities' downtime and increase the facilities' efficiency for peak utilization. These facilities also utilize oil skimming and recovery processes that remove residual oil from water delivered to our saltwater disposal facilities via pipeline or truck. We sell the oil recovered from these skimming processes, which contributes to our revenues. In addition to these saltwater disposal facilities, we provide management and staffing services to a saltwater disposal facility in which we own a 25% ownership interest (see Note 11).

2. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The accompanying Consolidated Financial Statements include our accounts and those of our controlled subsidiaries. All intercompany transactions and account balances have been eliminated in consolidation. Investments over which we exercise significant influence, but do not control, are accounted for using the equity method of accounting.

The accompanying Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") for consolidated financial information and in accordance with the rules and regulations of the Securities and Exchange Commission. The Consolidated Financial Statements include all adjustments considered necessary for a fair presentation of the financial position and results of operations for the periods presented.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and accompanying notes. Actual results could differ from those estimates.

Areas requiring the use of assumptions, judgments, and estimates include amounts of expected future cash flows used in determining possible impairments of property and equipment, intangible assets, and goodwill; the determination of fair values of assets acquired and liabilities assumed in business combinations; the allocation of goodwill to disposals of assets; useful lives of property, equipment and intangible assets; and the amount of future asset retirement obligations. Certain estimates are inherently imprecise and may change as future information becomes available. The use of alternative judgments and/or assumptions could result in different outcomes.

Fair Value Measurement

The Partnership utilizes fair value measurements to measure assets in a business combination or assess impairment of property and equipment, intangible assets, and goodwill. Fair value is the amount received from the sale of an asset or the amount paid to transfer a liability in an orderly transaction between market participants (an exit price) at the measurement date. Fair value is a market-based measurement considered from the perspective of a market participant. The Partnership uses market data or assumptions that it believes market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation. These inputs can be readily observable, market corroborated, or unobservable. The Partnership applies both market and income approaches for fair value measurements using the best available information while utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

The fair value hierarchy in GAAP prioritizes the inputs used to measure fair value, giving the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The Partnership classifies fair value balances based on the observability of those inputs. The three levels of the fair value hierarchy are as follows:

Level 1 – Quoted prices for identical assets or liabilities in active markets that management has the ability to access. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Inputs are other than quoted prices in active markets included in Level 1 that are either directly or indirectly observable. These inputs are either directly observable in the marketplace or indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured.

Level 3 – Inputs that are not observable for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management's best estimate of the assumptions market participants would use in determining fair value.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Contributions Attributable to General Partner

During the years ended December 31, 2017 and 2016, Holdings incurred overhead expenses on behalf of the Partnership totaling \$1.8 million and \$3.8 million, respectively. These costs represent administrative expenses incurred by Holdings in excess of amounts charged to the Partnership under our omnibus agreement. These expenses are reflected as *general and administrative* and as a component of the *net loss attributable to the general partner* in the Consolidated Statements of Operations for the years ended December 31, 2017 and 2016 and as *contributions attributable to general partner* in the Consolidated Statement of Owners' Equity.

In addition to incurring the expenses described above, Holdings provided the Partnership with additional financial support by making cash contributions of \$2.3 million and \$2.5 million in 2017 and 2016, respectively, as a reimbursement for certain expenditures incurred by the Partnership. These cash contributions are reflected as a *contribution attributable to general partner* in the Consolidated Statement of Owners' Equity and as a component of the *net loss attributable to the general partner* in the Consolidated Statements of Operations for the years ended December 31, 2017 and 2016.

Cash and Cash Equivalents

The Partnership considers all investments purchased with initial maturities of three months or less to be cash equivalents. Cash equivalents consist primarily of investments in highly-liquid securities. The carrying amounts of cash and cash equivalents reported in the balance sheet approximate fair value.

As of December 31, 2018, U.S. cash balances are insured by the Federal Deposit Insurance Corporation (FDIC) up to \$250,000 per financial institution. Canadian cash balances are insured by the Canada Deposit Insurance Corporation (CDIC) up to \$100,000 (Canadian Dollars) per financial institution. Our cash is primarily held at two financial institutions, and therefore in excess of the FDIC or CDIC insurance limits. We periodically assess the financial condition of the institutions where we deposit funds, and we believe our credit risk related to these funds was minimal at December 31, 2018.

Restricted Cash

Restricted cash was approximately \$0.6 million and \$0.5 million at December 31, 2018 and 2017, respectively. These amounts are included in *prepaid expenses and other* on the Consolidated Balance Sheets.

Accounts Receivable, Allowance for Bad Debts and Concentration of Credit Risk

We operate in the United States and Canada and grant unsecured credit to customers under normal industry standards and terms, and have established policies and procedures that allow for an evaluation of each customer's creditworthiness. We determine accounts receivable allowances for bad debts based on our assessment of the creditworthiness of our customers. Trade receivables are written off against the allowance when collection efforts have been exhausted and the receivable is deemed uncollectible. Recoveries of trade receivables previously written off are recorded when cash is received. We do not typically charge interest on past due trade receivables nor do we require collateral on our trade receivables. We had an allowance for doubtful accounts of less than \$0.1 million at December 31, 2018 and 2017. We recorded bad debt expense of less than \$0.1 million in each of the years ended December 31, 2018, 2017, and 2016. During the year ended December 31, 2017, we received \$0.3 million on accounts receivable previously written off which we recorded as a reduction to *general and administrative* on our Consolidated Statement of Operations.

We had two customers, Pacific Gas & Electric Company and Plains All America Pipeline, that represented more than 10% of total accounts receivable as of December 31, 2018. As of December 31, 2017, we had one customer, Pacific Gas & Electric Company, that represented more than 10% of total accounts receivable.

The majority of our revenues are generated in the United States. Total revenues generated in Canada were \$1.3 million, \$23.4 million, and \$31.2 million for the years ended December 31, 2018, 2017, and 2016, respectively.

Pacific Gas and Electric Bankruptcy

PG&E Corporation and its wholly-owned subsidiary Pacific Gas and Electric Company (collectively, "PG&E") filed for bankruptcy protection on January 29, 2019. PG&E is a significant customer that accounted for \$43.4 million of the revenue and \$6.4 million of the gross margin of our Pipeline Inspection segment during the year ended December 31, 2018. As of December 31, 2018, the assets on our Consolidated Balance Sheet included \$10.3 million of accounts receivable from PG&E. We collected \$1.0 million of this balance in January 2019 prior to PG&E's bankruptcy filing. We generated \$2.8 million of revenue from PG&E during the period from January 1, 2019 through January 28, 2019, bringing the total accounts receivable from PG&E to \$12.1 million as of the date of the bankruptcy filing. We have continued to provide services to PG&E after the bankruptcy filing. We have not recorded an allowance against the accounts receivable from PG&E at December 31, 2018, as we do not believe it is probable that we will ultimately be

unable to collect the full balance of the pre-petition receivables. However, due to uncertainties associated with the bankruptcy process, we cannot make assurances regarding the ultimate collection of these receivables nor can we make assurances regarding the timing of any such collections.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Property and Equipment

Property and equipment consists of land, land and leasehold improvements, buildings, facilities, wells and related equipment, field equipment, computer and office equipment, and vehicles. We record property and equipment at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repairs are expensed as incurred. We depreciate property and equipment on a straight-line basis over the estimated useful lives of the assets. Upon retirement, disposition, or impairment of an asset, we remove the cost and related accumulated depreciation from the balance sheet and report the resulting gain or loss, if any, in the Consolidated Statement of Operations.

Debt Issuance Costs

Debt issuance costs represent fees and expenses associated with securing the Partnership's Credit Agreement (see Note 6). Amortization of the capitalized debt issuance costs is recorded on a straight-line basis over the term of the Credit Agreement.

Income Taxes

As a limited partnership, we generally are not subject to federal, state or local income taxes. The tax on our net income is generally borne by the individual partners. Net income (loss) for financial statement purposes may differ significantly from taxable income (loss) of the partners as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. The aggregated difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner's tax attributes is not available to us.

The income of Tulsa Inspection Resources – Canada, ULC, our Canadian subsidiary, is taxable in Canada. Tulsa Inspection Resources – PUC, LLC ("TIR-PUC"), a subsidiary of our Pipeline Inspection segment that performs pipeline inspection services for utility customers, and Brown Integrity - PUC, LLC, a 51% owned subsidiary, have elected to be taxed as corporations for U.S. federal income tax purposes, and therefore, these subsidiaries are subject to U. S.

federal and state income taxes. The amounts recognized as income tax expense, income taxes payable, and deferred tax liabilities in our Consolidated Financial Statements represent the Canadian and U.S. taxes referred to above, as well as partnership-level taxes levied by various states, most notably, franchise taxes assessed by the state of Texas.

As a publicly-traded partnership, we are subject to a statutory requirement that 90% or more of our total gross income is classified as “qualifying income” (as defined by the Internal Revenue Code, related Treasury Regulations, and Internal Revenue Service pronouncements), determined on a calendar year basis. If our qualifying income does not meet this statutory requirement, we could be taxed as a corporation for federal and state income tax purposes. Our income has met the statutory qualifying income requirement for each year since our IPO.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

The Partnership evaluates uncertain tax positions for recognition and measurement in the Consolidated Financial Statements. To recognize a tax position, the Partnership determines whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more likely than not threshold is measured to determine the amount of benefit to be recognized in the Consolidated Financial Statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50% likely of being realized upon settlement. The Partnership had no uncertain tax positions that required recognition in the financial statements at December 31, 2018 or 2017. Any interest or penalties would be recognized as a component of income tax expense.

Revenue Recognition

Under Accounting Standards Codification ("ASC") 606 - *Revenue from Contracts with Customers*, an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Based on this accounting guidance, our revenue is earned and recognized through the service offerings of our three reportable business segments. Our sales contracts have terms of less than one year. As such, we have used the practical expedient contained within the accounting guidance which exempts us from the requirement to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract with an original expected duration of one year or less. We apply judgment