Cypress Energy Partners, L.P.
Form 10-K
March 23, 2016
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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 1 934

For the fiscal year ended December 31, 2015

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

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	61-1721523
(State or other jurisdiction of incorporation or organization)	**(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	**New York Stock Exchange**
(Title of each class)	(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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

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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 Annual Report on Form 10-K or any amendment to this Annual Report on Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company

(Do not check if a smaller reporting company)

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, 2015 was $69,085,578.

As of March 23, 2016, the registrant had 5,923,975 common units and 5,913,000 subordinated units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: N O N E

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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.

"Dig site"	The location where pipeline maintenance occurs by excavating the ground above the pipeline.
"*Flowback water*"	The fluid that returns to the surface during and for the weeks following the hydraulic fracturing process.
"*Gun barrel*"	A settling tank used for treating oil where oil and brine are separated only by gravity segregation forces.
"*Hydraulic fracturing*"	The process of pumping fluids, mixed with granular proppant, into a geological formation at pressures sufficient to create fractures in the hydrocarbon-bearing rock.
"*In-line inspection*"	An inspection technique used to assess the integrity of natural gas transmission pipelines from inside of the pipe.
"IPO"	Our initial public offering of common units representing limited partner interests in us.
"*Injection intervals*"	The part of the injection zone in which the well is screened or in which the waste is otherwise directly emplaced.
"*NGLs*"	Natural gas liquids. 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.
"*OPEC*"	The Organization of Petroleum Exporting Countries.
"*Pig tracking*"	The locating, mapping and monitoring of the in-line inspection pig.
"*Produced water*"	Naturally occurring water found in hydrocarbon-bearing formations that flows to the surface along with oil and natural gas.
"*Proppant*"	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*"	Salt water disposal.

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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;

"*CEM-BO*" refers to Cypress Energy Management – Bakken Operations, LLC, a wholly owned subsidiary of CEM LLC;

"*CEP LLC*" refers to Cypress Energy Partners, LLC, which became our wholly owned subsidiary at the closing of our initial public offering ("IPO");

"*CEP-TIR*" refers to Cypress Energy Partners – TIR, LLC, an indirect subsidiary of Holdings, and an owner of 673,400 common units representing 11.4% of our outstanding common units, 673,400 subordinated units representing 11.4% of our subordinated units 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;

"*CES LLC*" refers to Cypress Energy Services, LLC, a wholly owned subsidiary as of June 1, 2015 that performs management services for our salt water disposal ("SWD") facilities, as well as third party facilities. SBG Energy Services, LLC ("SBG Energy") owned 49% of CES LLC prior to the Partnership's June 1, 2015 acquisition of this ownership interest;

"*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;

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

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

"*Holdings II*" refers to Cypress Energy Holdings II, LLC, the owner of 671,250 common units representing 11.3% of our outstanding common units and 4,939,299 subordinated units representing 83.5% of our subordinated units;

"*IS*" refers to our Integrity Services business segment;

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

"PIS" refers to our Pipeline Inspection Services business segment;

"*TIR Entities*" refer collectively to TIR LLC and its subsidiary; TIR Holdings and its subsidiaries and TIR-NDE, all of which were 50.1% owned by CEP LLC from our IPO until February 1, 2015, at which time CEP LLC acquired the remaining interests from affiliates of Holdings and now owns 100%;

"*TIR Holdings*" refers to Tulsa Inspection Resources Holdings, LLC;

"*TIR LLC*" refers to Tulsa Inspection Resources, LLC;

"*TIR-Canada*" refers to Tulsa Inspection Resources – Canada ULC, a Canadian subsidiary of TIR Holdings;

"*TIR-Foley*" refers to Foley Inspection Services ULC, a Canadian subsidiary of TIR Holdings;

"*TIR-NDE*" refers to Tulsa Inspection Resources – Nondestructive Examination, 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; and

"W&ES" refers to our Water and Environmental Services business segment.

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 phrase 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 currently provide independent pipeline inspection and integrity services to producers and pipeline companies and water and environmental services with SWD facilities to U.S. onshore oil and natural gas producers and trucking companies. On January 21, 2014, we completed the IPO of our limited partner common units. As part of the transaction, affiliates of Holdings, conveyed an aggregate 50.1% interest in the TIR Entities in exchange for an aggregate 15.7% ownership in the Partnership. Affiliates of Holdings held the remaining 49.9% interest in the TIR Entities that was acquired by the Partnership effective February 1, 2015. As a result, the Partnership now owns 100% of the TIR Entities.

Our business is currently organized into three reportable segments: (1) Pipeline Inspection Services ("PIS"), (2) Integrity Services ("IS") and (3) Water and Environmental Services ("W&ES"). We also have a number of other lines of business in our IRS private letter ruling ("PLR") that would allow us to further diversify our business activities and lines of business serving the energy industry.

Through the PIS segment, we provide independent inspection services to various energy, public utility and pipeline companies in both the United States and Canada. Inspectors in this segment perform a variety of inspection services on midstream pipelines, midstream assets and infrastructure, gathering systems and distribution systems, including data gathering and supervision of third-party construction, inspection, and maintenance and repair projects. Results in this segment are driven primarily by the number and type of inspectors performing services for our customers and the fees they charge for those services, which depend on the nature and duration of the project. PIS is mainly comprised of the historical operations of the TIR Entities.

The IS segment primarily provides hydrostatic testing services to major natural gas and petroleum companies and pipeline construction companies of newly constructed and existing natural gas and petroleum pipelines. Field personnel in this segment perform various integrity services on newly constructed and existing oil and natural gas pipelines. Results in this segment are driven primarily by the number and skill level of field personnel performing the integrity services, size and length of the pipelines inspected, the complexity of services provided, the utilization of our equipment and the nature and duration of the projects, typically based on fixed bid agreements with customers. The IS segment is mainly comprised of the historical operations of Brown.

W&ES provides SWD services to oil and natural gas producers and trucking companies and consists of the operations of CEP LLC, which owns and operates eight commercial SWD facilities in the Bakken Shale region of the Williston Basin in North Dakota and two in the Permian Basin in Texas. We generate revenue by treating produced water and flowback water and injecting the water into our SWD facilities. Results are driven primarily by the volume of water injected into our SWD facilities and the fees charged related to these services. These fees are charged on a per barrel basis and vary based on the quantity and type of saltwater disposed, competitive dynamics and operating costs. Our SWD facilities currently utilize specialized equipment, full-time attendants, and remote monitoring to minimize downtime and increase efficiency for peak utilization and are located in close proximity to existing producing wells and expected future drilling sites, making our SWD facilities economically attractive to our current and future customers. These facilities also contain oil skimming processes that remove any remaining oil from flowback and produced water that has been delivered to the sites. We then generate revenue by selling the residual oil recovered from the water treatment process. In addition to the ten SWD facilities owned by CEP LLC, our consolidated subsidiary, CES LLC, provides management and staffing services for an additional SWD facility in the Bakken Shale region, pursuant to a management agreement. CES LLC also owns a 25% member interest in the managed well. The W&ES segment is directly tied to oil and gas activity and is impacted by lower commodity prices and newly completed oil and gas wells.

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Our Relationship with Cypress Energy Holdings, LLC

All of the equity interests in our general partner are owned by Holdings, which is owned by Charles C. Stephenson, Jr., various family trusts, a company controlled by our Chairman, Chief Executive Officer and President, Peter C. Boylan III and Henry Cornell. Holdings' owners bring substantial industry relationships and specialized, value-creation capabilities that we believe will 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 currently the 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 approximately 64.6% of our outstanding limited partner interests, Holdings and its affiliates have a strong incentive to support and promote the on-going 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:

Capitalize on compelling industry fundamentals.

PIS. We intend to continue to position ourselves as a trusted provider of high quality inspection services, as we believe the pipeline inspection services market offers attractive long-term growth fundamentals. 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 independent and 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 failure and requires 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. The current energy downturn has impacted our customers. However, most of our clients are investment–grade, well-capitalized companies that have long lead time projects requiring our services in addition to the ongoing maintenance and integrity work on their aging pipelines. Our business is not immune to the downturn, 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 opportunities.

IS. Effective May 1, 2015, we acquired Brown, effectively our Integrity Services business segment. We remain cautiously optimistic about this acquisition and the potential synergies that may develop between this segment and other current customers of the Partnership, as well as the growth and nurturing of the historical, ongoing IS business. It is our intent to capitalize on the solid structure and reputation of Brown and assist in expanding the geography of our IS business.

W&ES. We believe that the on-going 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 SWD facilities despite the recent downturn in the oil and gas industry as a whole. We plan to focus on pipeline opportunities with E&P companies that will secure water for our SWD facilities. Regulations continue to increase and we have proven to our customers that we are a trusted and dependable service provider. Increasingly, we are seeing E&P companies have their central procurement and Environment, Health and Safety ("EHS") groups inspect our SWD facilities. This trend should benefit our Partnership. Although the oil and gas industry can be cyclical in nature (as is evidenced by the current downturn), our current business strategy is such that 75% - 80% of our treated water is derived from existing wells. Although new drilling activity is currently curtailed and commodity oil prices have declined significantly, our focus will remain on the produced water that is generated for the life of an oil and gas well. With curtailed drilling activity and depressed oil prices, a portion of W&ES will suffer declines in volumes and pricing until the market rebounds leading to additional drilling and completions that, in turn, generate new produced water for the life of those newly completed oil and gas 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 SWD assets. The average age of our SWD facilities was 3.3 years at the end of 2015. We estimate that we utilized approximately 45% of the aggregate annual capacity of these facilities for the year ended December 31, 2015. Our permitted capacity is much higher than our estimated capacity. We are seeking to increase the utilization of our existing SWD 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 SWD facilities. Today we have six pipelines connected to our facilities. Because many of the costs of constructing and operating an SWD facility are either upfront capital costs or fixed costs, we expect that increased utilization of our existing SWD facilities over time will lead to increased gross margin and operating cash flow in W&ES. The downturn in the energy industry will continue to place pressure on both the volumes we process and the prices we are able to charge for our services.

Increase the number of pipelines connected to our SWD 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 trucking saltwater, we anticipate that they will increasingly prefer to utilize pipeline systems to transport their saltwater directly to SWD facilities. We intend to purchase or construct, whether alone or in joint ventures, saltwater pipeline systems that connect producers to our SWD facilities or newly developed SWD facilities. We continue to focus on increasing pipeline water delivered to our facilities. Our 2015 pipeline water volumes increased 67% from 2014. As a percentage of total water volume, pipeline water was 17% in 2014 and was 30% of total water volume in 2015. We will continue to focus on these potential pipeline opportunities.

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 W&ES 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 North Dakota, new inspection rules have been proposed in the legislature that may benefit PIS and IS. In addition, we intend to enhance our relationships with our customers in PIS by broadening the services we provide, 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. We intend to pursue accretive acquisitions that will complement the Partnership. Our business segments operate in industries that are fragmented, giving us the opportunity to make strategic and accretive acquisitions. We exercised discipline throughout 2014 and 2015 and avoided overpaying for acquisitions. We remain optimistic that good acquisition opportunities are currently present or will present themselves in the near future. We plan to expand W&ES by seeking water and solid acquisition opportunities in existing and additional high-growth resource plays throughout the U.S. that will diversify our customer base with a particular focus on pipeline opportunities directly with E&P customers. In addition, provided certain opportunities fit with our strategic plan of expanding our business (like the addition of our IS segment), we intend to grow PIS and IS by acquiring other strategic pipeline service companies that will allow us to broaden the suite of services we offer our existing customer base. In addition, we expanded our PIS ownership in February 2015 by acquiring the remaining 49.9% of the TIR Entities not previously owned by the Partnership.

Our Business Segments

Our business is currently operated in three reportable segments: (1) Pipeline Inspection Services ("PIS"), (2) Integrity Services ("IS") and (3) Water and Environmental Services ("W&ES"). Our IRS private letter ruling ("PLR") also includes other lines of business. Our long-term goal continues to be focused on diversifying the Partnership into other attractive lines of business including, but not limited to, traditional midstream activities, production chemicals, remote monitoring of energy infrastructure, etc. in addition to the continued expansion and build out of our segments. For information relating to revenues from external customers, operating income and total assets for each segment, refer to "*Note 14 – Segment Disclosures*" of our Consolidated Financial Statements included in "*Item 8. – Financial Statements and Supplementary Data*."

PIS

Overview. We believe that PIS is a leading provider of independent inspection services to the pipeline industry. We provide 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 approximately 85 pipeline inspection and integrity customers include oil and natural gas producers, pipeline owners and operators and public utility companies throughout North America. For the years ended December 31, 2015 and 2014 and for the period from June 26, 2013 through December 31, 2013, our Canadian operations generated less than $0.1 million, $0.6 million and $0.1 million, respectively, of the operating income attributable to PIS, representing less than 5% of the total PIS operating income in those years. Total long-lived assets located in Canada attributable to PIS as of December 31, 2015, 2014 and 2013 were $5.7 million, $2.5 million and $4.8 million, respectively.

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PIS offers independent inspection services for the following facilities and equipment:

- Transmission pipelines (oil, gas and liquids);
- Oil and natural gas gathering systems;
- Pump and compressor 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 the public safety. At the beginning of an engagement, our personnel meet with the customer to determine the scope of the project and related staffing needs. We then develop a customized, detailed staffing plan utilizing our proprietary database of more than 12,000 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, 2015 and 2014 and the period from June 26, 2013 through December 31, 2013, we employed or engaged an average of 1,392, 1,535 and 1,706 inspectors, respectively, in the U.S. and Canada. Through CF Inspection, a nationally approved Diverse Business Enterprise (woman-owned business), in which we own a 49% interest, we intend to provide services to current and future customers, including public utilities that have incentives to contract with minority and other diverse business enterprises.

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);
- Ultrasonic nondestructive examination services (using high-frequency sound waves to detect pipeline imperfections); and
- Related data management services.

IS

Overview. The IS 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. The company's primary emphasis is on recurring hydrostatic testing projects 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 petroleum 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 or pipeline construction companies are required to integrity-test newly constructed pipelines prior to placing them in service. In the IS segment, we contract directly with pipeline owners or 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 averages approximately 30 to 35 field technicians performing the testing services.

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W&ES Segment

Overview. Through W&ES, which specializes in water and environmental services, we own and operate ten SWD facilities, eight of which are in the Bakken Shale region of the Williston Basin in North Dakota and two of which are in the Permian Basin in west Texas. One of the North Dakota facilities was acquired effective December 1, 2014 and is connected to a pipeline with a large public E&P company's production. In addition to owning and operating the ten SWD facilities, we manage another SWD facility which is 25% owned by CES LLC that we built for third parties in the Bakken Shale region. W&ES is comprised of the operations of CEP LLC and its Predecessor.

Operations. W&ES 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, are originally injected into the well during the completion process and are partially recovered as flowback water. When it is removed, this flowback water contains salt, chemicals and residual oil. The drilling and completion phase typically occurs during the first 30 to 90 days following commencement of production of the life of a well. The oil and natural gas producer typically either transports the flowback water to one of our SWD facilities via pipeline or by truck or contracts with a trucking company for transport. Once the water is received at the SWD facility, we treat the water through a combination of separation tanks, gun barrels and chemical processes, store as necessary prior to injection and then inject into the SWD well at depths of at least 4,000 feet. Like 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 each 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 more slowly or in some cases, may even increase over time. The oil and natural gas producer separates the produced water from the production stream and either transports it to one of our SWD facilities by truck or pipeline or contracts with a trucking company to transport it to one of our SWD facilities. Once we receive the water at one of our SWD facilities, we filter and treat the water and then inject it into the SWD well at depths of at least 4,000 feet. 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 the wells.

Byproduct sales. Before we inject flowback and/or produced water into an SWD 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.

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

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, 2015, 2014 and 2013, produced water represented approximately 93%, 82% and 75%, respectively, of our total barrels of disposed water. This differentiates us from many competitors that focus on flowback and the associated skim oil revenue. 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 waste produced over the life of the wells.

Each of our SWD facilities are open 365 days per year. Our locations in North Dakota currently include onsite offices and sleeping quarters for our employees while they are on call. In Texas, we have an office and housing for management at our Pecos, Texas facility. 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 as well as identifying the identity of customers 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. We anticipate that more of our SWD facilities will be run through technological automation with off-site monitoring and control. Our facilities have been inspected and approved by several of our public E&P companies that have stringent approval standards and field audits performed by their EHS groups.

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The amount of saltwater disposed in our SWD facilities decreased 0.2 million barrels for the year ended December 31, 2015 to 18.9 million barrels as compared to the year ended December 31, 2014 due primarily to increased competition, as well as decreased oil and gas well activity in the regions we serve. The volume of saltwater decreased slightly from 19.7 million barrels for the year ended December 31, 2013 to 19.1 million barrels for the year ended December 31, 2014, a decline of approximately 3%, driven primarily by increased competition. Numerous new facilities opened during 2014 that competed for business with our locations.

As of December 31, 2015, we had an aggregate of approximately 115,000 barrels of maximum daily disposal capacity in the following SWD facilities, all of which were built using completion techniques consistent with current industry practices and utilizing well depths of at least 5,000 feet with injection intervals beginning at least 4,000 feet beneath the surface. Our permitted capacity is much higher.

Location	**County**	**In-service Date**	**Leased or Owned (3)**
Tioga, ND	Williams	June 2011	Owned
Manning, ND	Dunn	Dec. 2011	Owned
Grassy Butte, ND	McKenzie	May 2012	Leased
New Town, ND (1)	Mountrail	June 2012	Leased
Pecos, TX (1)	Reeves	July 2012	Owned
Williston, ND	Williams	Aug. 2012	Owned
Stanley, ND	Mountrail	Sept. 2012	Owned
Orla, TX (1)	Reeves	Sept. 2012	Owned
Belfield, ND	Billings	Oct. 2012	Leased
Watford City, ND (2)	McKenzie	May 2013	Leased
Arnegard, ND (1)	McKenzie	August 2014	Leased

(1) Currently receives piped water.
(2) We own a 25.0% non-controlling interest in this SWD facility.
(3) Certain SWD facilities are constructed on land leased under long term arrangements.

Principal Customers

PIS

Customers of PIS 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, 2015, 2014 and 2013, PIS had approximately 85 customers. The five largest customers in this segment generated approximately 58%, 65% and 71% of our segment revenue for the years ended December 31, 2015 and 2014 and for the period from June 26, 2013 through December 31, 2013, respectively. For the years ended December 31, 2015 and 2014, we had three customers that individually accounted for more than 10% of segment revenues. For the period from June 26, 2013 through December 31, 2013, two pipeline inspection services customers accounted for more than 10% of our segment revenue.

IS

IS customers are primarily pipeline construction companies and in some instances, the pipeline owners. During the period from May 1, 2015 (acquisition date) through December 31, 2015, we had 61 customers. Our ten largest customers in terms of revenue generated approximately 70% of our total segment revenue. We had two customers that each generated 10% or more of the total segment revenues.

W&ES

W&ES customers are oil and natural gas exploration and production 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, 2015, 2014 and 2013, we had approximately 178, 206 and 228 customers, respectively, in W&ES. Our ten largest customers generated approximately 62%, 60% and 55% of W&ES revenue for the years ended December 31, 2015, 2014 and 2013, respectively. For the years ended December 31, 2015 and 2014, there was one customer that generated 10% or more of W&ES revenue. There were no customers for the year ended December 31, 2013 that generated 10% or more of W&ES segment revenues.

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Competition

PIS

The pipeline inspection business is highly competitive. PIS' 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. We believe that the principal competitive factors in our business include gaining and maintaining customer approval to service their pipelines 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.

IS

The pipeline integrity services business is highly competitive. We believe that the principal competitive factors in our business are customer service and price. Our competition consists primarily of smaller regional integrity firms.

W&ES

The oilfield waste treatment, water and environmental services, and disposal business is highly competitive with relatively low entry barriers. During 2014, 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 beginning 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 our customers, who may have the option of using internal disposal methods instead of outsourcing to us or another third-party disposal company. We believe that the principal competitive factors in our businesses include gaining and maintaining customer approval of treatment and SWD facilities, location of facilities in relation to customer activity, reputation, safety record, reliability of services, track record of environmental & regulatory compliance, customer service, insurance and price.

Seasonality

PIS

Inspection work varies depending upon the geographic location of our customers. As we expand our relationships with public utility commissions in California and other locations with moderate climates, the seasonality of our inspection and integrity business is expected to decline. The third and fourth quarters are historically the most active for our pipeline inspection services as our customers focus on completing projects by year end. In addition, our Canadian customers use inspection services the most during the fourth and first quarters of the year when the tundra is frozen. We believe our presence across various regions in the U.S. and our presence in Canada helps mitigate the seasonality of our business.

IS

As most of the work in this segment is currently performed in the southern United States, weather does not create a seasonality issue. However, business has historically been slower in the first calendar quarter, presumably due to the budgeting cycles of our customers.

W&ES

The overall operations and financial performance of our Bakken Shale 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 when the outside temperature is lower. Seasonality is not typically a major factor in the Permian Basin in west Texas, however, the 2013-2014 winter saw more ice and snow than normal leading to reduced activity as reported by a number of large E&P companies operating in the region.

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.

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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 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. For example, 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 to legally transport such waste. Texas already required the same.

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. We estimate that we will incur costs of less than $0.1 million over the next one to three years in connection with continued monitoring and remediation of known contamination at our facilities.

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 Exploration & Production ("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 September 2010, a nonprofit environmental group filed a petition with the EPA requesting reconsideration of the RCRA E&P waste exemption. To date, the EPA has not taken any action on the petition. If the RCRA E&P waste exemption is repealed or modified, we could become subject to more rigorous and costly operating and disposal requirements.

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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, including Texas, 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 is 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.

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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 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 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 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 Texas and 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 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. This rule has been stayed pending the resolution of various legal challenges.

The EPA is conducting a study of the potential impacts of hydraulic fracturing activities on drinking water. The EPA released a draft of its report for peer review and public comment in 2015. 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.

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. Some states, including Texas, have promulgated rules or guidance in response to these concerns. 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. These new seismic permitting requirements applicable to disposal wells impose more stringent permitting requirements and are likely to result in added costs to comply or, perhaps, may require alternative methods of disposing of salt water 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, but 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 our business and affairs that is required to manage and conduct our operations. As of December 31, 2015, 2014 and 2013, that entity employed 27, 15 and ten people, respectively, who provide direct support for our operations, none of whom are covered by collective bargaining agreements. Under the terms of our amended and restated omnibus agreement, we reimburse CEM LLC for the provision of various general and administrative services incurred for our benefit, for direct expenses incurred by CEM LLC on our behalf and for expenses allocated to us as a result of our becoming a public entity. In addition, PIS does not have any employees. All of the employees that conduct the PIS business do it through CEM TIR, providing the necessary personnel resources to PIS. PIS employed or engaged 1,002, 1,147 and 1,476 inspectors as of December 31, 2015, 2014 and 2013, respectively, of which 971, 1,131 and 1,397 were employed directly by CEM TIR. The inspectors not employed by CEM TIR are contractors engaged in our Canadian operations. The number of employees in the PIS group vary month to month and project to project. The Tulsa headquarters group of PIS consists of approximately 70 employees who were also employed by CEM TIR. Virtually all of our inspector employees are billable to clients and they work in the field on client assets and infrastructure including, but not limited to, pipelines. Our IS segment directly employed 70 individuals at December 31, 2015.

We also had a co-employment relationship between CEM LLC and a third-party management company that employed nine and ten people as of December 31, 2014 and 2013, respectively, working at our SWD facilities in west Texas. The co-employment arrangement was terminated in January 2015 and all employees are now employed solely by CEM LLC. There were six people employed by CEM at December 31, 2015 that worked at our Texas facilities. CEM LLC also owns CEM-BO, which provides staff for our North Dakota SWD facility operations. As of December 31, 2015, 2014 and 2013, CEM-BO employed approximately 28, 39 and 41 employees, respectively. CEM LLC and CEM-BO have been reimbursed a management fee to compensate them for the cost of the Texas and North Dakota employees, benefits and various other services provided to us.

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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 carry a variety of insurance coverages for our operations. However, our insurance may not be sufficient to cover any particular loss or may not cover all losses, and losses not covered by insurance would increase our costs. Also, insurance rates have been subject to wide fluctuation, and changes in coverage could result in less coverage, increases in cost or higher deductibles and retentions.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 SWD 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 W&ES, 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 PIS and IS, 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.

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. 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 have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cash reimbursement to our general partner and its affiliates to enable us to pay our minimum quarterly distributions to holders of our units.

In order to pay the minimum quarterly distribution of $0.3875 per unit per quarter, or $1.55 per unit on an annualized basis, we will require available cash of approximately $4.6 million per quarter, or $18.3 million per year, based on the number of common and subordinated units outstanding as of March 23, 2016. We may not have sufficient available cash from operating surplus each quarter to enable us to pay the minimum quarterly distribution. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge, and the margins we realize, from PIS, IS and W&ES;
- the number and types of projects conducted by PIS and IS and the volume of saltwater handled in W&ES;
- 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 and other SWD facilities;
- 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.

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

- the 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;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- the amount of cash reserves established by our general partner; and
- other business risks affecting our cash levels.

We would not have had sufficient cash available for distribution to pay the full minimum quarterly distribution on all of our units for the year ended December 31, 2013.

We must generate approximately $18.3 million of cash available for distribution to pay the aggregate minimum quarterly distributions for four quarters on all units outstanding as of March 23, 2016. The amount of cash available for distribution that we generated during the year ended December 31, 2013 on a pro forma basis would have been sufficient to pay 100% of the aggregate minimum quarterly distribution on all common units, and 54.2% of the aggregate minimum quarterly distributions on our subordinated units for that period. Our ability to pay the minimum quarterly distribution is subject to various restrictions and other factors described in more detail under *"Item 5 – Market for Registration's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities – Our Cash Distribution Policy."* If we are not able to generate additional cash for distribution to our unitholders in future periods, we may not be able to pay the full minimum quarterly distribution or any amount on our common or subordinated units, in which event the market price of our common units may decline materially.

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.

W&ES 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 the Baker Hughes 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 of 488 rigs in April 1999. From January 2010 through February 2015, the aggregate U.S. weekly rig count has remained above 1,220 rigs, reaching a peak of 2,026 rigs in November 2011 and declining to 571 rigs in February 2016. The prices of crude oil and related products has dropped substantially in the fourth quarter of 2014 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. Further downward pressure on commodity prices continued throughout 2015, and we expect continuing low commodity prices through 2016. If crude oil prices do not recover, or take longer to recover than anticipated, exploration and production companies, pipeline owners and operators and public utility or local distribution companies in the regions we conduct our business may reduce capital spending on maintaining their pipelines or oil and natural gas production. W&ES constitutes approximately 4% and 6% of our revenue for the years ended December 31, 2015 and 2014. 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.

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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 expectations about future prices, of oil and natural gas;
- the cost of exploring for, developing, producing and delivering oil and natural gas, including fracturing services;
- the expected rate of decline of current oil and natural gas production;
- the discovery rates of new oil and natural gas reserves;
- available pipeline and other transportation capacity;
- lead times associated with acquiring equipment and products and availability of personnel;
- weather conditions, including hurricanes, tornadoes, 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 their

oil and natural gas reserves;

the level of oil production by non-OPEC countries and the available excess production capacity within OPEC;

oil refining capacity and shifts in end-customer preferences toward fuel efficiency;

potential acceleration in the development, and the price and availability, of alternative fuels;

the availability of water resources for use in hydraulic fracturing operations;

public pressure on, and legislative and regulatory interest in, federal, state, and local governments to ban, stop, significantly limit or regulate hydraulic fracturing operations;

technical advances affecting energy consumption;

the access to and cost of capital for 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 PIS segment are substantial, which will reduce our borrowing capacity for other purposes and reduce our cash available for distribution.

PIS has substantial working capital needs throughout the year as we pay the majority of our inspectors on a weekly basis, but typically receive payment from our customers 45 to 90 days after the services have been performed. We intend to make borrowings under our credit facility to fund the working capital needs of PIS, and these borrowings will reduce the amount of credit available for other uses, such as working capital for our water disposal business, acquisitions and growth projects, and increase interest expense, thereby reducing 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 we experience any delays in payment by our pipeline inspection and integrity services customers, we may be subject to significant and rapid increases in our working capital needs that could require us to make further borrowings under our revolving credit facility or impact our ability to pay our minimum quarterly distributions.

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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 the treatment of their water and environmental 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 SWD facilities, and some producers recycle saltwater on-site. Most oilfield operators, including many of our customers, have numerous abandoned wells that could be licensed for use in the disposition of internally generated waste and third-party waste in competition with us. Additionally, technologies may be developed that could be used by our customers to recycle saltwater and to recover oil through oilfield waste processing. 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 competition could adversely impact our financial position, results of operations, demand for services, cash flows or our ability to make required payments on debt outstanding.

We have many competitors in PIS, IS and W&ES. Other companies offer similar pipeline inspection and integrity services or third-party saltwater disposal in our primary markets. Some of our customers also compete with us in the treatment and disposal sector by offering 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 control our costs aggressively and maximize efficiency in order to maintain acceptable operating margins; however, we may be unable to do so and remain competitive on a cost-for-service basis. In addition, existing and future competitors may develop or offer services or new technologies that have pricing, location or other advantages over the services we provide, including a lower cost of capital.

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 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 SWD facilities. Therefore, there is a heightened risk 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, 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 71%, 78% and 80% of our consolidated revenue for the years ended December 31, 2015, 2014 and the period from June 26, 2013 through December 31, 2013. There were three customers that accounted for more than 10% of revenues for the years ended December 31, 2015 and 2014; Enbridge Energy Partners, Enterprise Products Partners and Plains All America Pipeline. For the period from June 26, 2013 through December 31, 2013, Enbridge Energy Partners and Enterprise Products Partners each individually made up more than 10% of consolidated revenues of PIS. Revenues from these customers resulted from inspection operations, which are activities conducted by our PIS 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.

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

Many of our customers are oil and natural gas companies that are facing 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 as 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.

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 trucking companies to transport saltwater to our SWD facilities. In recent years, certain states, including North Dakota and Texas, and counties have increased enforcement of weight limits on trucks used to transport raw materials on their public roads. 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 to legally transport such wastes. It is possible that the states, counties and cities in which W&ES 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 in transporting saltwater to our SWD facilities and increased costs to transport saltwater to our facilities, which may either increase our operating costs or reduce the amount of saltwater transported to our SWD facilities. This could decrease our operating margins or amounts of saltwater disposed at our SWD facilities 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.

Fuel is a significant operating expense for our trucking customers, and a significant increase in fuel prices will result in increased transportation costs to them. 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 drive down the prices our trucking company customers would be willing to pay, which would reduce our revenues and impact our ability to make distributions to our unitholders. Insurance is a significant operating expense for our trucking customers, and a significant increase in insurance prices or decrease in availability of coverage results in increased transportation costs to them.

Volumes of residual oil recovered during the saltwater water 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, therefore, our profitability.

Approximately 8% and 22% of our revenue for the years ended December 31, 2015 and 2014, respectively, in W&ES 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 begin recovering 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.

Our business may be difficult to evaluate because we have a limited period of historical financial and operating data.

Prior to June 26, 2013, our historical financial and operating data does not include PIS. Prior to May 1, 2015, our historical financial and operation data does not include IS. As a result, we have provided only limited financial and operating data regarding the consolidated business that we operate. The historical financial and operating results of our business may be materially different from our future financial and operating results. Our future results will depend on our ability to efficiently manage our integrated operations and execute our business strategy. Our historical financial performance should not be considered reliable indicators of our future performance.

In addition, we face challenges and uncertainties in financial and operational planning as a result of the limited access to historical data regarding volumes of oilfield waste treated and related sales and pricing. Our first facilities were opened during 2011, and other companies in the SWD industry do not regularly release historical data related to their SWD facilities. This limited data may make it more difficult for us and our investors to evaluate our business and prospects and to forecast our future operating results.

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

We have grown rapidly since our inception in 2012, primarily through acquisitions. We believe that our future success depends on our ability to manage the rapid growth that we have experienced and the demands from increased responsibility on our management personnel. The following factors could present difficulties to us:

- organizational challenges common to large, expansive operations;
- administrative burdens;
- employee insurance;

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- 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 these potential difficulties.

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

We will distribute 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.

Our utilization of existing capacity, expansion of existing SWD facilities and construction or purchase of new SWD 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 SWD facilities and construct or purchase new SWD facilities. The construction of a new SWD facility or the extension, renovation or expansion of an existing SWD facility, such as by connecting the SWD facility to 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 or 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 SWD 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.

Holdings is developing or seeking to purchase several water and environmental services assets and facilities that may be suitable to our operations in the future. We may have the opportunity to make acquisitions directly from Holdings and its affiliates in the future. 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.

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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 Integrity, LLC and a 49.0% interest in CF Inspection Management, LLC. 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.

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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.

On December 24, 2013, we entered into a $120.0 million Credit Agreement, which we used to replace the TIR Entities' existing revolving credit facility and mezzanine facilities. On October 21, 2014, the Credit Agreement was amended to increase the aggregate availability under the Credit Agreement from $120.0 million to $200.0 million. 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 it would meet those ratios and tests.

The provisions of our new and future credit agreements 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 new and future 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 new or future 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 existing and future debt levels may limit our flexibility to obtain financing and to pursue other business opportunities.

As of December 31, 2015, we had $140.9 million of indebtedness outstanding under our Credit Agreement. We will have the ability 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 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.

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 SWD facilities in North Dakota and Texas, each with its own regulatory program 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 the development and operation of waste treatment and storage facilities and in connection with the disposal and transportation of certain types of waste. The applicable 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, pressures, 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 SWD 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.

Delays in obtaining permits by our customers 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.

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

Obtaining a permit to own or operate an SWD 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 SWD facilities. In particular, the regulatory agencies of the two states in which we operate require us to post letters of credit in connection with the operation of our SWD facilities. As we acquire additional SWD facilities or expand our existing SWD facilities, these obligations will increase. Additionally, in the future, regulatory agencies may require us to increase the amount of our closure bonds at existing SWD facilities. We have accrued approximately $117 thousand on our balance sheet related to our future closure obligations of our SWD facilities as of December 31, 2015. However, actual costs could exceed our current expectations, as a result of, among other things, federal, state or local government regulatory action, increased costs charged by service providers that assist in closing SWD facilities and additional environmental remediation requirements. Increased regulatory requirements regarding our existing or future SWD 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 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 Texas and 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 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. This rule has been stayed pending the resolution of various legal challenges.

The EPA is conducting a study of the potential impacts of hydraulic fracturing activities on drinking water. The EPA released a draft report for peer review and public comment in 2015. 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 water recycling efforts by oil and natural gas producers which would decrease the volume of saltwater delivered to our SWD facilities.

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 for oil and natural gas producers due to reasons such as prolonged drought. For example, according to the Lower Colorado River Authority, during 2011, Texas experienced the lowest inflows of water of any year in recorded history. As a result of this severe drought, some local water districts have begun restricting the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. 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 prohibits recyclable water from being disposed of in wells. If oil and natural gas producers in Texas 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 Texas SWD facilities (or in other states that adopt similar programs). 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.

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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 that the underground injection of produced water into disposal wells has triggered seismic activity in certain areas. Some states, including Texas, have promulgated rules or guidance in response to these concerns. 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. These new seismic permitting requirements applicable to disposal wells impose more stringent permitting requirements and are likely to result in added costs to comply or, perhaps, may require alternative methods of disposing of salt water 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 September 2010 an environmental group filed a petition with the EPA requesting reconsideration of this RCRA exemption. To date, the EPA has not taken any action on the petition. 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.

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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 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.

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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 is 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, 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 can materially impact our business.

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 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.

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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 equipment defects, vehicle accidents, explosions, earthquakes, lightning strikes 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 SWD facilities because fiberglass is less corrosive than other materials traditionally utilized. These tanks are, however, more prone to lighting 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 SWD 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 SWD facilities develop a leak depending upon the terms of the contracts.

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 SWD facilities are located exclusively in North Dakota and Texas. This concentration could disproportionately expose us to operational, economic and regulatory risk in these areas. Additionally, our SWD facilities currently comprise ten 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 the our markets, including, for example, transportation constraints, adverse regulatory developments, or other adverse events at one of our SWD facilities, could have a significantly greater impact on our financial condition, results of operations and cash flows than if we were more diversified.

Changes in the provincial royalty rates and drilling incentive programs in Canada could decrease the oil and gas exploration and pipeline activities in Canada, which could adversely affect the demand for our pipeline inspection services.

Certain provincial governments collect royalties on the production from lands owned by the government of Canada. These fiscal royalty regimes are reviewed and adjusted from time to time by the respective provincial governments for appropriateness and competitiveness. Any increase in the royalty rates assessed by, or any decrease in the drilling incentive programs offered by, a provincial government could negatively affect the drilling activity and the need for pipelines and gathering systems, which could adversely affect the demand for our pipeline inspection services.

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 SWD facilities.

Some oil and natural gas producers are focusing on developing and utilizing non-water fracturing techniques, including those utilizing 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 as these wells would not produce flowback water. In particular, our SWD facilities in west Texas could be negatively affected by these new technologies, as the drought conditions of west Texas make fracturing with materials other than water attractive alternatives.

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 W&ES 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 PIS and IS could decrease if the demand for our inspectors decrease, if our safety record declines and 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 increasing costs of operations. In addition, new agreements for our services in these business segments entered into by us may not be obtainable on terms acceptable to us or, if obtained, may not be obtained on terms 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, PIS and IS 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 is limited. A significant increase in the wages paid by competing employers 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 PIS and IS 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, and our Vice President and Chief Financial Officer, G. Les Austin. 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 SWD 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 SWD 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 hurricanes, seismic activity such as earthquakes, lightning strikes, 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. As a result, our revenue and results of operations could be materially adversely affected.

The seasonal nature of the oilfield service industry in Canada may negatively affect us and our customers.

In Canada, the level of activity in the oilfield services industry is influenced by seasonal weather patterns. As warm weather returns in the spring, the winter's frost comes out of the ground (commonly referred to as "spring break up") rendering many secondary roads incapable of supporting heavy loads, and as a result, road bans are implemented prohibiting heavy loads from being transported in certain areas. As a result, the movement of the heavy equipment required for drilling and well servicing activities is restricted and the level of activity of our Canadian operations and the operations of our customers are consequently reduced.

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The amount of cash we have available for distribution to holders of our common and subordinated 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, which will be affected by depreciation, amortization, impairment loss and other non-cash items. 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 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. As with other yield-oriented securities, our unit price will be impacted by our 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 those of third-parties, 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 technology 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, and (except as described below) our independent registered public accounting firm to attest to, 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, or our independent registered public accounting firm’s 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 currently utilize two distinct accounting systems for our business, one for PIS and one for the remainder of our businesses. We may experience difficulties consolidating these accounting systems, or may be delayed in implementing our plan to consolidate these systems, and any such difficulties or delay may impact our ability to timely file reports with the SEC and/or to comply with the covenants under our current and future credit facilities.

We are currently in the process of implementing a new Enterprise Resource Planning (“ERP”) business solution to create a system of integrated applications to manage our businesses and automate many functions related to financial reporting, human resources and other services. It is our intent through this ERP 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. Any failure(s) during the implementation process of this ERP 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 ERP system implementation, we can provide no assurance as to our, or our independent registered public accounting firm’s 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.

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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. However, for as long as we are an "emerging growth company" under the Jumpstart Our Business Startups Act of 2012, or the JOBS Act, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal controls over financial reporting pursuant to Section 404. We could be an emerging growth company for up to five years following the closing of our IPO. Even if we conclude that our internal controls over financial reporting are effective, our independent registered public accounting firm may issue a report that is qualified if it is not satisfied with our controls or the level at which our controls are documented, designed, operated or reviewed, or if it interprets the relevant requirements differently from us.

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

An enterprise-wide information system will be 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 anticipate from the implementation of our enterprise-wide information system.

We are currently in the process of implementing a new ERP business solution to create a system of integrated applications to manage our businesses and automate many functions related to financial reporting, human resources and other services. It is our intent through this ERP 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 ERP 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 detriment and that of our unitholders. 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 the 2015 year-end, Holdings and its affiliates own a 64.6% limited partner interest in us and own and control our general partner and appoint all of the officers and directors of our general partner. Although our general partner has a duty to manage us in a manner that is 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;

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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;

expenditure, 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, the amount of adjusted operating surplus generated in any given period and the ability of the subordinated units to convert into common units;

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 a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period;

our partnership agreement permits us to classify up to $10.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our subordinated units or 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; 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 our general partner's 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 of the resolution of a conflict of interest by the conflicts committee of the board of directors of our general partner;
- 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 and subordinated 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 expiration 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 will pay Holdings a quarterly administrative fee of $1.0 million for the provision of certain general and administrative expenses. This fee is subject to increase by an amount equal to the producer price index 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. The amount of this fee is below the amount we would expect to reimburse the general partner for such services in the absence of the fee. 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 we expect our payment for these services to increase. This increase may 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 expiration 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 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. The vote of the holders of at least 66 2/3% of all outstanding common units and subordinated units voting together as a single class is required to remove our general partner. Holdings and its affiliates own 64.6% of the common units and subordinated units. Also, if our general partner is removed without cause during the subordination period and common units and subordinated units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically be converted into common units, and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests.

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“Cause” is narrowly defined under our partnership agreement to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the general partner liable for actual fraud or willful misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of our general partner because of the unitholders’ dissatisfaction with our general partner’s performance in managing our partnership will most likely result in the termination of the subordination period and conversion of our subordinated units to common units.

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 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. 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;

because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;

the ratio of taxable income to distributions may increase;

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

the market price of 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.

Holdings and CEP-TIR hold 1,344,650 common units and 5,612,699 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and may convert earlier under certain circumstances. 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. Holdings and its affiliates own approximately 29.2% of our common units. At the end of the subordination period, assuming no additional issuances of common units by us (other than upon the conversion of the subordinated units), our general partner and its affiliates will own approximately 64.6% of our outstanding common units and therefore, would not be able to exercise the call right at that time.

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, 2015, there are only 4,190,747 publicly traded common units held by public unitholders. Holdings and CEP-TIR own 1,344,650 common units and 5,612,699 subordinated units, representing an aggregate 58.8% limited partner interest in us. 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.

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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 it 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, it will be entitled to receive a number of common units equal to that number of common units that would have entitled their holder to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions to our general partner on the 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 the cash distributions it receives related to its incentive distribution rights and may, therefore, desire to 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.

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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 a maximum of 35.0%, 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. Additionally, the U.S. Department of the Treasury and the IRS have issued proposed Treasury regulations (“Treasury Regulations”) under the Internal Revenue Code of 1986, as amended (the “Internal Revenue Code”), that provide industry-specific guidance regarding whether income earned from certain activities will constitute qualifying income within the meaning of section 7704 of the Internal Revenue Code. It is possible that these proposed Treasury Regulations will undergo significant changes prior to becoming final Treasury Regulations. 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. These rules are not applicable to us for tax years beginning on or prior to December 31, 2017.

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 related 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 are in the process of requesting a ruling from the IRS upon which, if granted, we may rely with respect to the qualifying nature of the income from certain activities conducted by PIS and IS. If we do not obtain a favorable ruling from the IRS, we will be required to continue to conduct these activities in subsidiaries that are treated as corporations for U.S. federal income tax purposes and are subject to corporate-level income taxes.

We are in the process of requesting a ruling from the IRS upon which, if granted, we may rely with respect to the qualifying nature of the income from certain activities conducted by PIS and IS. If the IRS is unwilling or unable to provide a favorable ruling with respect to such income, we will continue to be subject to corporate-level tax on the revenues generated by such activities. Conversely, if the IRS does provide a favorable ruling, we may choose to conduct such activities in the future in a tax pass-through entity. Such restructuring may result in a significant, one-time tax liability and other costs, which will reduce our cash available for distribution.

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 Treasury and the IRS recently 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.

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The sale or exchange of 50.0% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for U.S. federal income tax purposes.

We will be considered to have technically terminated our partnership for U.S. federal income tax purposes if there is a sale or exchange of 50.0% or more of the total interests in our capital and profits within a twelve month period. For purposes of determining whether the 50.0% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for U.S. federal income tax purposes, but instead we would be treated as a new partnership for U.S. federal income tax purposes. If treated as a new partnership, we must make new tax elections, including a new election under Section 754 of the Internal Revenue Code, and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

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

As of December 31, 2015, W&ES had an aggregate of approximately 115,000 barrels of maximum daily disposal capacity in the following SWD facilities, all of which were built since June 2011 with new well bores, using completion techniques consistent with current industry practices and utilizing well depths of at least 5,000 feet and injection intervals beginning at least 4,000 feet beneath the surface:

Location	**County**	**In-service Date**	**Leased or Owned (3)**
Tioga, ND	Williams	June 2011	Owned
Manning, ND	Dunn	Dec. 2011	Owned
Grassy Butte, ND	McKenzie	May 2012	Leased
New Town, ND (1)	Mountrail	June 2012	Leased
Pecos, TX (1)	Reeves	July 2012	Owned
Williston, ND	Williams	Aug. 2012	Owned
Stanley, ND	Mountrail	Sept. 2012	Owned
Orla, TX (1)	Reeves	Sept. 2012	Owned
Belfield, ND	Billings	Oct. 2012	Leased
Watford City, ND (2)	McKenzie	May 2013	Leased
Arnegard, ND (1)	McKenzie	August 2014	Leased

(1) Currently receives piped water.
(2) We own a 25.0% non-controlling interest in this SWD 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 Avenue, Suite 300, Tulsa, Oklahoma 74105. The lease expires in February 2018 unless terminated earlier under certain circumstances specified in our lease. In our PIS segment, we also lease office space in Calgary, Alberta, Canada for our foreign operations.

For our IS segment, we lease office space in Houston and Odessa Texas. Adjacent to the Houston office, we lease a staging facility for operational storage and staging. In addition, we own an office building and staging and storage facility in Giddings, Texas.

ITEM 3. LEGAL PROCEEDINGS

Stuart v. TIR

In July 2014, a group of former minority shareholders of Tulsa Inspection Resources, Inc. ("TIR Inc."), formerly an Oklahoma corporation, filed a civil action in the United States District Court for the Northern District of Oklahoma against TIR LLC, members of TIR LLC, and certain affiliates of TIR LLC's members. TIR LLC is the successor in interest to TIR Inc., resulting from a merger between the entities that closed in December 2013 (the "TIR Merger"). The former shareholders in TIR Inc. claim that they did not receive sufficient value for their shares in the TIR Merger and are seeking rescission of the TIR Merger or, alternatively, compensatory and punitive damages. The Partnership is not named as a defendant in this civil action. TIR LLC and the other defendants have been advised by counsel that the action lacks merit. In addition, the Partnership anticipates no disruption in its business operations related to this action.

Flatland Resources v. CES LLC

In September 2015, Flatland Resources I, LLC and Flatland Resources II, LLC, two of our management services customers (under common ownership) initiated a civil action in the District Court for the McKenzie County District of the State of North Dakota against CES LLC. The customers claim that CES LLC breached the management agreements and interfered with their business relationships, and seek to rescind the management agreements and recover any damages. The customers initiated this lawsuit upon dismissal from federal court due to lack of jurisdiction of CES LLC's lawsuit against the customers seeking to enforce the management agreements. CES LLC subsequently filed an answer and counterclaims, as well as a third party complaint against the principal of the customers seeking to enforce the management agreements and other injunctive relief, as well as monetary damages. The court subsequently granted CES's motion to transfer venue to the Grand Forks County District Court. We believe that the possibility of the Partnership incurring material losses as a result of this action is remote.

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 15, 2016, the closing price for the common units was $8.68 per unit and there were approximately 3,475 unitholders of record and beneficial owners (held in street name) of the Partnership's common units.

We have also issued 5,913,000 subordinated units, for which there is no established public trading market. 5,612,699 of the subordinated units are effectively held by Holdings and its controlled affiliates, either directly or indirectly through its ownership of CEP-TIR. The remaining 300,301 subordinated units are held directly by certain beneficial owners and management.

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The high and low trading prices for our common units and distribution paid per unit by quarter were as follows:

Quarter Ended	High	Low	Distribution (a)	
March 31, 2014	$26.00	$19.55	$ 0.301389	(b)
June 30, 2014	24.97	21.65	0.396844	
September 30, 2014	25.78	22.22	0.406413	
December 31, 2014	24.93	11.54	0.406413	
March 31, 2015	19.83	11.82	0.406413	
June 30, 2015	18.00	12.41	0.406413	
September 30, 2015	16.64	9.21	0.406413	
December 31, 2015	12.99	7.02	0.406413	

(a) Represents declared distributions associated with each respective quarter. Distributions were declared and paid within 45 days following the close of each quarter in accordance with our cash distribution policy.

(b) Reflects a prorated portion of the targeted minimum quarterly cash distribution of $0.3875 for the period from the closing of the Partnership's IPO on January 21, 2014 through March 31, 2014.

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. We intend to continue to make cash distributions to unitholders on a quarterly basis, although there is no assurance as to the future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors.

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 (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.

During Subordination Period

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter in the following manner during the subordination period:

first , 100.0% to the common unitholders, pro rata, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter;
second , 100.0% to the common unitholders, pro rata, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period;
third , 100.0% to the subordinated unitholders, pro rata, until we distribute for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and
thereafter, in the manner described in “*General Partner Interest and Incentive Distribution Rights*” below.

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The preceding discussion is based on the assumptions that we do not issue additional classes of equity securities. Unless earlier terminated pursuant to the terms of our partnership agreement, the subordination period will extend until the first business day of any quarter beginning after December 31, 2016, that the Partnership meets the financial tests set forth in the Partnership Agreement, but may end sooner if the Partnership meets additional financial tests.

After Subordination Period

Our partnership agreement requires that after the subordination period, we make distributions of available cash from operating surplus for any quarter in the following manner:

- *first* , 100.0% to all unitholders, pro rata, until we distribute for each outstanding 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.

The preceding discussion is based on the assumptions that we do not issue additional classes of equity securities.

General Partner Interest and Incentive Distribution Rights

Incentive distribution rights represent the 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. Our general partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in the partnership agreement.

The following discussion assumes there are no arrearages on common units and that our general partner continues to own the incentive distribution rights.

If for any quarter:

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

then, our partnership agreement requires that we distribute any additional available cash from operating surplus for that quarter among the unitholders and the general partner in the following manner:

first, 100.0% to all unitholders, pro rata, until each unitholder receives a total of $0.445625 per unit for that quarter (the "first target distribution");
second, 85.0% to all unitholders, pro rata, and 15.0% to our general partner, until each unitholder receives a total of $0.484375 per unit for that quarter (the "second target distribution"); and
third, 75.0% to all unitholders, pro rata, and 25.0% to our general partner, until each unitholder receives a total of $0.581250 per unit for that quarter (the "third target distribution"); and
thereafter, 50.0% to all unitholders, pro rata, and 50.0% to our general partner.

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, 2015.

Unregistered Sales of Equity Securities

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

Issuer Purchases of Equity Securities

None.

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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*."

On January 21, 2014, we completed the initial public offering ("IPO") of our limited partner common units. In connection with the IPO, Holdings II, a wholly-owned subsidiary of Holdings, conveyed a 100% interest in CEP LLC. Prior to its contribution to the Partnership, CEP LLC distributed to Holdings its interest in four subsidiaries. In addition to CEP LLC, affiliates of Holdings contributed 50.1% of their interest in the TIR Entities (the Partnership's PIS segment). The Partnership then subsequently conveyed this 50.1% interest to CEP LLC. We have recast prior period financial data and information of Cypress Energy Partners, L.P. to reflect CEP LLC's distribution of its four subsidiaries to Holdings, which were originally acquired on December 31, 2012, and to reflect the conveyance of CEP LLC and the TIR Entities to the Partnership at the closing of our IPO, as if the contribution of CEP LLC had occurred as of March 15, 2012 and the contribution of the TIR Entities had occurred as of June 26, 2013, the date affiliated members of the Partnership acquired a controlling interest in the TIR Entities. 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 Integrity, LLC, a hydrostatic testing integrity services business creating our IS 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.

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	Cypress Energy Partners, L.P.				Predecessor (d)	
	Year Ended December 31, 2015 (a)	**Year Ended December 31, 2014**	**Year Ended December 31, 2013 (b) *Recast***	**Period from March 15 (Inception) through December 31, 2012 (c) *Recast***	**Year Ended December 31, 2012**	**Period from June 1 (Inception) through December 31, 2011**
	(in thousands , except cash distributions per unit and operational data)					
Income Statement Data						
Revenues	$371,191	$404,418	$249,133	$619	$12,203	$2,944
Costs of services	326,261	355,355	213,690	309	3,662	503
Gross margin	44,930	49,063	35,443	310	8,541	2,441
General and administrative expense	23,795	21,321	12,467	2,056	477	138
Depreciation, amortization and accretion	5,427	6,345	5,164	99	1,398	123
Impairments	6,645	32,546	4,131	-	-	-
Operating income (loss)	9,063	(11,149)	13,681	(1,845)	6,666	2,180
Interest expense, net	5,656	3,208	4,000	-	111	35
Offering costs	-	446	1,376	-	-	-
Net income (loss)	4,091	(15,179)	4,355	(1,845)	6,595	2,162
Net income attributable to non-controlling interests	599	4,973	22	-	-	-
Net income (loss) attributable to partners / controlling interests	3,492	(20,152)	4,333	-	-	-
Balance Sheet Data - Period End						
Total assets	$192,687	$189,842	$240,590	$79,990	$27,588	$14,476
Long-term debt	140,900	77,600	75,000	-	2,314	2,798
Total parent net investment and owners' equity	40,702	100,428	135,547	77,746	24,769	9,265
Cash Flow Data						
Cash flows from operating activities	$26,921	$13,016	$7,154	$(2,244)	$7,246	$1,106
Cash flows from investing activities	(64,879)	(2,286)	5,779	(65,613)	(15,236)	(10,860)
Cash flows from financing activities	42,501	(16,030)	13,363	68,341	8,425	9,901
Cash distributions per unit (subsequent to IPO) (e)	1.63	1.51	-	-	-	-
Capital expenditures	1,857	2,286	4,329	65,613	15,236	10,860
Other Financial Data						
Adjusted EBITDA	$24,663	$28,499	$23,110	$(1,746)	$8,104	$2,320
Adjusted EBITDA attributable to partners / controlling interests	23,147	19,841	23,079	(1,746)	8,104	2,320
Operational Data						
Average number of inspectors	1,392	1,535	1,706			
Average revenue per inspector per week	$4,711	$4,773	$4,952			
Average number of field personnel (f)	33					

Average revenue per field personnel per week	$20,261					
Total barrels of saltwater disposed (in thousands)	18,864	19,066	19,541	551	8,674	1,641
Average revenue per barrel	$0.78	$1.18	$1.14	$1.12	$1.41	$1.79

(a) Activity for the year ended December 31, 2015 includes operations of Brown (IS segment) from the May 1, 2015 acquisition date through the end of the year.

(b) Activity for the year ended December 31, 2013 includes operations of the TIR Entities (PIS segment) from the June 26, 2013 acquisition date through the end of the year.

(c) During the period from its inception through the date of its acquisition of the Predecessor on December 31, 2012, CEP LLC had no significant assets or operations.

(d) Includes activities of certain entities that were not contributed to the Partnership.

(e) Includes February distributions related to the previous quarter ended December 31.

(f) Represents Brown (IS segment) personnel from the May 1, 2015 acquisition date through the end of the year.

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Non-GAAP Financial Measures

We define Adjusted EBITDA as net income, plus interest expense, depreciation and amortization expenses, income tax expense, offering costs, impairments, non-cash allocated expenses and equity-based compensation, less the gain on the reversal of contingent consideration. Adjusted EBITDA is used as a supplemental financial measure 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 Adjusted EBITDA will provide useful information to investors in assessing our financial condition and results of operations. Net income is the GAAP measure most directly comparable to Adjusted EBITDA. Adjusted EBITDA should not be considered an alternative to net income. Because Adjusted EBITDA may be defined differently by other companies in our industry, our definition of Adjusted EBITDA may not be comparable to a similarly titled measure of other companies, thereby diminishing their utility. As a result, Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

The following table presents a reconciliation of net income (loss) to Adjusted EBITDA and to distributable cash flow, as applicable, for each of the periods indicated.

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

	Year Ended December 31,	
	2015 (a)	**2014**

		(in thousands)	2013 (b)
Net income (loss)	$4,091	$ (15,179)	$4,355
Add:			
Interest expense	5,656	3,208	4,000
Depreciation, amortization and accretion	6,004	6,513	5,261
Impairments	6,645	32,546	4,131
Income tax expense	452	468	15,237
Non-cash allocated expenses	648	497	-
Offering costs	-	446	1,376
Equity based compensation	1,167	-	-
Less:			
Gain on reversal of contingent consideration	-	-	11,250
Adjusted EBITDA	$24,663	$ 28,499	$23,110
Adjusted EBITDA attributable to non-controlling interests	1,516	8,658	31
Adjusted EBITDA attributable to partners / controlling interests	$23,147	$ 19,841	$23,079
Adjusted EBITDA attributable to general partner (c)	-	1,651	
Adjusted EBITDA attributable to limited partners	$23,147	$ 18,190	
Less:			
Cash interest paid, cash taxes paid, maintenance capital expenditures	5,940	381	
Distributable cash flow attributable to limited partners	$17,207	$ 17,809	

(a) Activity for the year ended December 31, 2015 includes operations of Brown (IS segment) from the May 1, 2015 acquisition date through the end of the year. Also, because the Partnership acquired the remainder of the TIR Entities February 1, 2015 and CES LLC on June 1, 2015, adjusted EBITDA attributable to non-controlling interests for the year ended December 31, 2015 includes the activity of the TIR Entities and CES LLC through their acquisition dates and the activity of Brown since May 1, 2015.

(b) Activity for the year ended December 31, 2013 includes operations of the TIR Entities (PIS segment) from the June 26, 2013 acquisition date through the end of the year. Also, because Holdings and other affiliates owned 100% of the TIR Entities, there is no adjusted EBITDA attributable to non-controlling interests for the year ended December 31, 2013 associated with the TIR Entities.

(c) Adjusted EBITDA attributable to general partner in 2014 represents activity prior to the Partnership's IPO.

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The following table presents a reconciliation of net cash provided by operating activities to Adjusted EBITDA, as applicable, for each of the periods indicated.

Reconciliation of Net Cash Provided by Operating Activities to Adjusted EBITDA

	Year Ended December 31,		
	2015 (a)	**2014**	**2013 (b)**
		(in thousands)	
Cash flows provided by operating activities	$26,921	$ 13,016	$7,154
Changes in trade accounts receivable, net	(9,039)	(6,650)	8,793
Changes in prepaid expenses and other	(233)	933	(283)
Changes in accounts payable and accrued liabilities	1,222	2,964	1,910
Change in income taxes payable	196	15,612	(15,816)
Offering costs	-	446	1,376
Equity-based compensation	-	(785)	(90)
Interest expense (excluding non-cash interest)	5,109	2,494	2,781
Income tax expense (excluding deferred tax benefit)	484	468	15,237
Other	3	1	2,048
Adjusted EBITDA	$24,663	$ 28,499	$23,110

(a) Activity for the year ended December 31, 2015 includes operations of Brown (IS segment) from the May 1, 2015 acquisition date through the end of the year.

(b) Activity for the year

ended December 31, 2013 includes operations of the TIR Entities (PIS segment) from the June 26, 2013 acquisition date through the end of the year.

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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. At the closing of our IPO on January 21, 2014, CEP LLC and a 50.1% interest in the TIR Entities were contributed to us and became our Water and Environmental Services ("W&ES") segment and our Pipeline Inspection Services ("PIS") segment, respectively. These contributions were treated for accounting purposes as a combination of entities under common control and the results of CEP LLC are included as if the contributions had occurred as of March 15, 2012 and the results of the TIR Entities were included in our financial statements for periods subsequent to June 26, 2013, the date Holdings acquired a controlling interest. Brown Integrity, LLC (our Integrity Services ("IS") segment) was acquired effective May 1, 2015, and the results of this segment have been included in our financial statements for periods subsequent to that date.

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 exploration and production ("E&P") and midstream companies and their vendors in our PIS and IS segments throughout the United States and Canada. The PIS segment is comprised of the operations of the TIR Entities and the IS segment is comprised of the operations of Brown. The economic characteristics of Brown were sufficiently dissimilar from our previous Pipeline Inspection and Integrity Services, thus creating a new segment. As such, the Pipeline Inspection and Integrity services segment was renamed Pipeline Inspection Services and we created the Integrity Services segment. We also provide SWD and other water and environmental services to U.S. onshore oil and natural gas producers and trucking companies through our W&ES segment. The W&ES segment is comprised of the historical operations of CEP LLC that were contributed to us. We operate ten SWD facilities, eight of which are in the Bakken Shale region of the Williston Basin in North Dakota and two of which are in the Permian Basin in west Texas. We also have management agreements in place to provide staffing and management services to third party SWD facilities in the

Bakken Shale region (two of which are currently in dispute). W&ES customers are oil and natural gas exploration and production companies and trucking companies operating in the regions that we serve. 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 the PIS 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 IS segment primarily by providing hydrostatic testing services to major natural gas and petroleum companies and pipeline constructions companies of newly constructed and existing natural gas and petroleum pipelines. We generally charge our customers in this segment on a fixed bid basis depending 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 depends 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.

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We generate revenue in the W&ES segment primarily by treating flowback and produced water and injecting the saltwater into our SWD facilities. Our results in W&ES are driven primarily by the volumes of produced water and flowback water we inject into our SWD facilities 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 SWD 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 the 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 NGLs, 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 NGLs. Similarly, oil and natural gas production levels nationally and regionally generally tend to positively correlate with drilling activity. Revenues in this segment are recognized when the service is performed and collectability of fees is reasonably assured. We also generate revenue managing a SWD facility for a fee.

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 in North Dakota. 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 and intend to review these measurements frequently for consistency and trend analysis. These metrics include:

- inspector headcount in PIS;
- field personnel headcount in IS;
- saltwater disposal and residual oil volumes in W&ES;
- operating expenses;
- segment gross margin;
- Adjusted EBITDA; and
- distributable cash flow.

Inspector Headcount

The amount of revenue we generate in PIS 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 and distribution systems and the legal and regulatory requirements relating to the inspection and maintenance of those assets.

Field Personnel Headcount

The amount of revenue we generate in IS 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, as well as 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.

Saltwater Disposal and Residual Oil Volumes

The amount of revenue we generate in W&ES 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. Our revenues from produced water, flowback water or residual oil sales are generated pursuant to contracts that are short-term in nature. Revenues in this segment are recognized when the service is performed and collectability of fees is reasonably assured. The volumes of saltwater disposed at our SWD 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 the 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 NGLs, 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 NGLs. Similarly, oil and natural gas production levels nationally and regionally generally tend to positively correlate with drilling activity.

Approximately 8%, 22% and 25% of our segment revenue for the years ended December 31, 2015, 2014 and 2013, respectively, in W&ES 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 in North Dakota. 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 that we evaluate include costs of services, general and administrative, and depreciation and amortization.

Costs of services. Employee-or-contractor-related costs and per diem expenses are the primary costs of services components in PIS and IS. These expenses fluctuate from period to period based on the number, type and location of projects on which we are engaged at any given time. We seek to maximize the profitability of our operations in part by minimizing, to the extent appropriate, expenses directly tied to operating and maintaining our assets. Repair and maintenance costs, employee-related costs, residual oil disposal costs and utilities expenses are the primary cost of services components in W&ES. 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. We seek to manage our operations and repair and maintenance capital expenditures on our SWD facilities and related assets by scheduling repairs and maintenance to avoid significant variability in our maintenance capital expenditures, downtime and minimize their impact on our cash flows.

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 $4.04 million (payable in equal quarterly installments) for the provision of certain partnership overhead expenses. 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. To the extent that Holdings incurs overhead expenses in excess of our annual administration fee that are attributable to the operations of the Partnership, these expenses are reflected in our Statements of Operations as incremental general and administrative expense and treated as an equity contribution attributable to our General Partner.

Included in this administrative fee are our incremental 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; legal fees; investor relations, registrar and transfer agent fees; director and officer liability insurance costs 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 expiration of our amended and restated omnibus agreement could be substantial and will reduce the amount of cash we have available to distribute to unitholders.

Depreciation, amortization and accretion. Depreciation, amortization and accretion expense primarily consists of our estimate of the decrease in value of our capitalized tangible and intangible assets as a result of using the assets over time. Depreciation and amortization are recorded on a straight-line basis. We estimate our assets have useful lives ranging from 3 to 39 years. The facilities, wells and equipment constituted approximately 75%, 82% and 83% of the cost basis of our fixed assets as of December 31, 2015, 2014 and 2013 respectively, and have useful lives of 5 to 15 years.

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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, plus interest expense, depreciation and amortization expenses, income tax expense, offering costs, impairments, non-cash allocated expenses and equity-based compensation, less the gain on the reversal of contingent consideration. We use distributable cash flow, defined as Adjusted EBITDA less net cash interest paid, cash taxes paid and maintenance capital expenditures, to analyze our performance. Distributable cash flow will not reflect changes in working capital balances, which could be significant, as headcounts of PIS vary from period to period. Adjusted EBITDA is a non-GAAP, supplemental financial measure used by management and by external users of our financial statements, such as investors, commercial banks and research 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 will provide useful information to investors in assessing our financial condition and results of operations. Net income 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 measure. Each of these non-GAAP financial measures has important limitations as an analytical tool because it excludes some but not all 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

Pipeline Inspection Services

Demand remains solid for our pipeline inspection services as we operate in a very large market with many customer prospects that we do not currently serve. We continue to focus on new lines of business to serve our existing customers. The majority of our clients are public investment grade companies with long planning cycles that lead to healthy backlogs of new long-term projects, in addition to maintaining their existing pipeline networks that also require inspection and integrity services. The public utility company ("PUC") segment of the industry that brings natural gas to homes and businesses remains an area with material growth potential. We believe that with increasing regulatory requirements, and the aging U.S. and Canadian pipeline infrastructure, that the PIS business is more insulated from changes in commodity prices in the near term as has been the case in the past. However, a prolonged depression in oil and natural gas prices could lead to a downturn in demand for our services.

Our average headcount and revenue per inspector metrics continue to trend below our expectations and the prior two years. We have seen certain customer's 2015 project start dates postponed to 2016 and, to date, have not seen a significant increase in our average inspector headcounts. One of our customers cancelled a major project in the Southwest portion of the United States that had been awarded to us after regulators required them to re-route the project. We anticipate that our inspector headcounts will increase as work previously postponed begins. The downturn in energy prices has required many of our customers that rely more heavily on commodity prices to focus on reducing their operating costs. Several clients have sought to reduce the rates paid to inspectors to reduce their inspection costs. We have recently bid on several new projects and have begun to increase staffing for new projects awarded. Many of our customers are in the process of finalizing 2016 operating budgets (including inspection service costs) for submission to their board of directors. Many new projects and opportunities are awarded by our customers in the fourth quarter and the first quarter of the calendar year.

Integrity Services

We remain cautiously optimistic about the acquisition of Brown and the potential synergies that may develop between IS and other current customers of the Partnership, as well as the growth and nurture of its historical, ongoing business. Brown acquired a competitor in the third quarter of 2014 and had some challenges associated with an unexpected illness of that company's founder and CEO that required him to resign. As a result, we have recruited some new talent to the organization. Brown currently operates in 6 states, compared with the more than 45 states that the TIR Entities (through our PIS segment) operate in. We are currently considering expanding Brown's geography on both the West coast, Louisiana and in the Northeast. We continue to see excellent new bidding opportunities and our success rate on new work continues to improve, leading us to increased utilization of our equipment and field personnel.

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Water and Environmental Services

In our W&ES segment, the continued decline in the market price of crude oil has a direct impact on our revenues associated with the sale of residual oil. It also has an indirect impact on our water disposal volumes and revenues, depending on how oil and gas producers in the vicinity of our facilities react to declining oil and/or gas prices with respect to their rig and new drilling activity.

Many producers have announced material and significant cuts in their future capital budgets and drilling activities that would reduce new flowback water and produced water and, although unlikely, could potentially stop production on existing wells, which would have a direct impact on the volumes of disposed water and residual oil recovery at our facilities. The material decline in rig count and new drilling activity in many basins, including the Bakken and the Permian, has led to lower water volumes, reduced skim oil volumes and pricing pressures. Many of our E&P customers have requested and been granted pricing concessions to help them cope with the lower commodity prices. In the majority of the basins in the country, new SWD facilities were developed to support the previous rig counts and activity levels prior to the sharp contraction in activity and commodity prices. These events have led to excess SWD facility supply relative to current demand in many locations, including the Bakken and the Permian that in turn, has led to aggressive pricing. We have always focused on produced water vs. flowback water and therefore we believe we are less impacted than many competitors. During the year, approximately 93% of our water volume was from produced water disposal. We are clearly being impacted by lower water volumes in the markets we serve, lower skim oil volumes as our flowback volumes decline, lower per barrel water pricing and lower per barrel oil pricing. We are focused on reducing operating costs and identifying operating efficiencies in an effort to offset the financial impact of declining market volumes and prices. Additionally, we continue to focus on piped water opportunities to secure additional long term volumes of produced water for the life of the oil and gas wells' production. Piped water continues to represent a growing percentage of our total volume. We also provide management services for third party SWD facilities. In September 2015, Flatland Resources I, LLC and Flatland Resources II, LLC, two of our management services customers (under common ownership) initiated a civil action in the District Court for the McKenzie County District of the State of North Dakota against CES LLC. The customers claim that CES LLC breached the management agreements and interfered with their business relationships, and seek to rescind the management agreements and recover any damages. The customers initiated this lawsuit upon dismissal from federal court due to lack of jurisdiction of CES LLC's lawsuit against the customers seeking to enforce the management agreements. CES LLC subsequently filed an answer and counterclaims, as well as a third party complaint against the principal of the customers seeking to enforce the management agreements and other injunctive relief, as well as monetary damages. The court subsequently granted CES's motion to transfer venue to the Grand Forks County District Court. We believe that the possibility of the Partnership incurring material losses as a result of this action is remote.

Despite the severe downturn in the energy market to date, we are currently anticipating the total barrels of water disposed to level off at fourth quarter 2015 volumes. We also anticipate the decline in average revenue per barrel disposed as the result of the management fee matter noted above, competitive market pricing pressures and lower oil prices to stabilize absent further declines in oil commodity pricing. Revenue per barrel is comprised of (i) water volumes and disposal price per barrel, (ii) skim oil volumes and the selling price for oil per barrel and (iii) third party management fees (including wage reimbursements). We have seen a substantial increase in the number of acquisition opportunities in the W&ES segment. It appears that some potential sellers are coming to terms with the reduced valuations, volumes, and cash flows impacting the industry. We will continue to actively pursue the right opportunities with the same discipline that protected the Partnership during a heated market in 2014 that drove up valuations to unsustainable levels. We also continue to evaluate some interesting opportunities for pipelines and SWD's directly with E&P companies seeking to monetize their midstream assets.

Despite the depressed economy and lower overall oil and gas commodity pricing, the Partnership has continued throughout 2015 and anticipates through 2016 to sustain a level positive cash flow and expects to continue cash distributions consistent with prior distributions. If commodity prices recover in 2016 leading to increased oil and gas production activity, we would hope to see the opportunity to resume planned, deliberate increases in our cash distributions.

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 would 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.

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As a company with less than $1.0 billion in revenue during its last fiscal year, we qualify as an “emerging growth company” as defined in the Jumpstart Our Business Startups Act of 2012, or the JOBS Act. As an emerging growth company, we have elected to opt out of the exemption that allows emerging growth companies to extend the transition period for complying with new or revised financial accounting standards (this election is irrevocable).

Impairments of Long-Lived Assets

As prescribed by ASC 360-10-05, *Property, Plant and Equipment-General Impairment or Disposal of Long-Lived Assets,* we assess property, plant and equipment ("PP&E") 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 exceeds the future undiscounted cash flows expected from the asset, we recognize an impairment charge for the excess of carrying value of the asset over its estimated fair value. Determination as to whether and how much an asset is impaired 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 W&ES segment, we evaluate property and equipment for impairment at the SWD facility level. Our computations utilize judgments and assumptions that include the undiscounted future cash flows, discounted future cash flows, estimated fair value of the asset, 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. PP&E is not a significant component of our PIS or IS segments.

During the years ended December 31, 2015, 2014 and 2013, we identified impairment indicators at some of our SWD facilities and reviewed the associated property and equipment for impairment. We recognized impairment charges of $6.6 million, $12.8 and $3.4 million during the years ended December 31, 2015, 2014 and 2013, respectively, for assets that were determined to be impaired. 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 broad range of our PP&E and the number of assumptions involved in the estimates. Favorable changes to some assumptions might have avoided 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 near future.

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. Given the time it takes to obtain pertinent information to finalize acquired companies' balance sheets, it may be several quarters before we are able to finalize those initial fair value estimates. Accordingly, it is not uncommon for the initial estimates to be subsequently revised. The results of operations of acquired businesses are included in the Consolidated Financial Statements from the acquisition date.

Identifiable Intangible Assets

Our recorded identifiable intangible assets of $32.5 million and $30.2 million at December 31, 2015 and 2014, respectively, primarily represent customer lists and trademarks and trade names, amortized straight-line 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, 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 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. There were no impairments of identifiable intangible assets during the years ended December 31, 2015 or 2014. During the year ended December 31, 2013, the partnership determined that one of its trade names in PIS was impaired and recorded an impairment charge of $0.7 million. The fair value was determined using a discounted cash flow analysis applied to the expected royalty values generated from the use of the trade name. Management's estimates of the future royalties associated with the use of the trade name were based on forecasted total revenues. Actual results could vary which could have further impact on the value of the trade name.

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Goodwill

At December 31, 2015 and 2014, the Partnership had $65.3 million and $55.5 million of goodwill, respectively. Goodwill is not amortized, but is subject to annual reviews on November 1 for impairment at a reporting unit level. The reporting unit or units used to evaluate and measure goodwill for impairment are determined primarily from the manner in which the business is managed or operated. A reporting unit is an operating segment or a component that is one level below an operating segment. In accordance with ASC 350 "*Intangibles — Goodwill and Other*", we have assessed the reporting unit definitions and determined that PIS, IS and W&ES are the appropriate reporting units for testing goodwill impairment. The accounting estimate relative to assessing the impairment of goodwill is a critical accounting estimate for each of our reporting segments.

For our PIS and IS reporting units, we performed qualitative assessments to determine whether the fair values of the reporting units were more likely than not to be less than their respective carrying values. Our evaluation consisted of assessing various qualitative factors, including current and projected future earnings, capitalization, current customer relationships and projects and the impact of lower crude oil prices on our earnings. The qualitative assessments in these reporting units indicated the fair values of the reporting units exceeded their carrying values and the reporting units were not at risk for potential goodwill impairment.

For our W&ES reporting unit, after giving consideration to certain qualitative factors, including trends in the energy industry and recorded impairments of property and equipment, we elected to perform a quantitative goodwill impairment analysis. We computed the fair value of the reporting unit considering multiple valuation methodologies, including a market approach (market price multiples of comparable companies) and an income approach (discounted cash flow analysis). These approaches are consistent with the requirement to utilize all appropriate valuation techniques as described in ASC 820-10-35-24 "*Fair Value Measurements and Disclosures*." Given recent declines in the price of crude oil and the related impact on the valuations of energy related companies, relevant market data was difficult to obtain and was of limited usefulness. Accordingly, we relied heavily on the use of the income approach for the valuation of the reporting unit.

A discounted cash flow analysis requires us to make various assumptions about sales, operating margins, capital expenditures, working capital and growth rates. These assumptions are based on our budgets, business plans, economic projections, and anticipated future cash flows. In determining the fair value of our reporting units, we were required to make significant judgments and estimates regarding the impact of anticipated economic factors on our business. The forecasts used in these analyses make certain assumptions about future pricing, volumes and expected maintenance capital expenditures. Assumptions are also made for "normalized" perpetual growth rates for periods beyond the long range financial forecast period. Critical estimates that are used as part of these evaluations include, among other things, the discount rate applied to future earnings reflecting a weighted average cost of capital rate and earnings growth assumptions. Our estimate of water volumes disposed and revenue per barrel of water disposed are important assumptions used in our discounted cash flow analysis for our SWD facilities.

Our estimates of fair value are sensitive to changes in all of these variables, certain of which relate to broader macroeconomic conditions outside our control. As a result, actual performance in the near and longer-term 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, such as continued increases in oil field development in our customer base. In addition, some of the inherent 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. While we believe we have made reasonable estimates and assumptions to calculate the fair value of our reporting units and other intangible assets, it is reasonably possible that a material change could occur that would require a goodwill impairment charge in the near future.

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The W&ES segment has experienced increased competition in the regions in which we operate which has resulted in declining volumes and increased pricing pressure. Steady and continued declines in oil prices have intensified competitive pressures and had a direct impact on our revenues. Many of our customers have announced significantly reduced drilling programs in the Bakken. The decline in drilling will directly impact the amount of flowback and produced water that we process and dispose. The energy downturn is also expected to continue to negatively impact our pricing as our customers look for ways to reduce costs. In addition, as we process lower water volumes, in particular flowback water volumes directly attributable to drilling, we will recover less skim oil.

Based on our quantitative analysis, we determined that goodwill for W&ES was not impaired as of our 2015 annual review date. Because additional SWD property and equipment were impaired in the fourth quarter due to continued declines in disposed volumes and depressed prices, we updated our W&ES valuation through December 31, 2015. Based on these 2015 analyses, we determined that the carrying value of the W&ES reporting unit was less than the estimated fair market value and therefore, there was no goodwill impairment adjustment for 2015. In 2014, we determined that the carrying value of the W&ES reporting unit exceeded the fair value of the reporting unit resulting in a goodwill impairment charge of $19.8 million. Further declines in cash flows in the W&ES segment could result in declines in our fair market valuation of W&ES and, consequently, additional goodwill impairments.

Depreciation Methods, Estimated Useful Lives of Property and Equipment

Depreciation expense represents the systematic and rational write-off of the cost of property and equipment, net of residual or salvage value (if any), to the results of operations for the periods the assets are used. We depreciate our property and equipment using the straight-line method, which results in recording depreciation expense evenly over the estimated life of the individual assets. The estimate of depreciation expense requires us to make assumptions regarding the useful economic lives and residual values of our assets. At the time we acquired and placed our property and equipment in service, we developed assumptions about such lives and residual values that we believe are reasonable; however, circumstances may develop that could require us to change these assumptions in future periods, which would change our depreciation expense amounts prospectively. We currently use a life of 15 years for wells and related equipment, which include subsurface well completion and other improvements. We use a life of 9 years for tanks, plumbing and storage tanks and generally 5 years for our testing equipment and trailers. We use lives of 30 – 39 years for buildings. We believe that these lives represent the economic lives of the assets and that substantial capital expenditures would need to be incurred to extend their economic lives. Examples of such circumstances include changes in laws and regulations that limit the estimated economic life of an asset; changes in technology that render an asset obsolete; or changes in expected salvage values. At this time, we do not believe that it is likely that any of these circumstances will occur.

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:

The Partnership has recorded impairments of long-lived assets, intangible assets and goodwill in 2015, 2014 and 2013 totaling \$6.6 million, \$32.5 million and \$4.1 million, respectively.

Effective June 1, 2015, the Partnership acquired the remaining 49% interest in Cypress Energy Services, LLC ("CES LLC") previously held by a related party. As a result of this transaction, the 2014 Consolidated Financial Statements reflect a non-controlling interest of 49% of CES LLC from the IPO date through the end of the period, while the 2015 Consolidated Financial Statements reflect a 49% non-controlling interest from January 1, 2015 through May 31, 2015 related to CES LLC. The 51% ownership in CES LLC was not acquired until October 1, 2013; accordingly, the financial data presented does not reflect the results of operations of CES LLC prior to that date.

Effective May 1, 2015, the Partnership acquired a 51% controlling interest in Brown, a hydrostatic integrity services business. The Consolidated Financial Statements will include Brown in the IS segment from this date forward, including a 49% non-controlling interest.

At the closing of the IPO, we acquired a 50.1% interest in each of the TIR Entities with Holdings and certain affiliates continuing to hold the remaining 49.9% interest ("Retained Interest"). The non-controlling interest is reduced by certain interest charges as outlined in our amended and restated omnibus agreement. The contribution of interests in the TIR Entities to the Partnership has been treated as a reorganization of entities under common control. Accordingly, the results of operations and assets and liabilities of the TIR Entities are included in the historical financial information of the Partnership for periods from June 26, 2013, the date Holdings obtained control of the TIR Entities. Effective February 1, 2015, the Partnership acquired the remaining 49.9% non-controlling ownership interest of the TIR Entities from affiliated parties. Accordingly, the 2014 Consolidated Financial Statements reflect a non-controlling interest of 49.9% of the TIR Entities from the IPO date through the end of the period, while the Consolidated Financial Statements for 2015 reflect a 49.9% non-controlling interest from January 1, 2015 through January 31, 2015 related to the TIR Entities (less certain amounts charged directly to the non-controlling interests in both periods).

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In the fourth quarter of 2014, the Partnership acquired an additional SWD facility in the Bakken shale region of North Dakota. Therefore, the results for the year ended December 31, 2015 include the activity for the additional well.

The years ended December 31, 2014 and 2013 reflect non-recurring offering costs of $0.4 million and $1.4 million, respectively, incurred in conjunction with our IPO. In addition, net income of the Partnership for the period from January 1, 2014 through January 20, 2014 (the period prior to our IPO) is reflected as *net income attributable to general partner* in the Consolidated Statements of Operations for the year ended December 31, 2014.

General and administrative expenses have increased as a result of operating as a publicly traded partnership. At the closing of the IPO, CEP LLC, the Partnership and other affiliates entered into an omnibus agreement with Holdings. Among other things, the agreement calls for an annual administrative fee to be paid by the Partnership in the amount of $4.0 million (adjusted annually as provided for in the omnibus agreement), payable in quarterly installments to Holdings, for providing the Partnership with certain overhead services, including executive management services by certain officers of our General Partner, compensation expense, including stock-based compensation expense for employees required to manage and operate our business as well as the costs of operating a publicly traded partnership, including costs associated with SEC reporting requirements, tax return and Schedule K-1 preparation and distribution, independent registered public accounting firm fees, investor relations activities and registrar and transfer agent fees.

Interest expense will not be comparable between periods presented as a result of our Credit Agreement entered into in December 2013 that resulted in more favorable credit terms as compared to previous periods and increased interest expense because of increased borrowings related to acquisitions made by the Partnership during the periods presented. Borrowings under the Credit Agreement were initially used to, among other things, refinance outstanding obligations of the TIR Entities which had significantly higher interest rates. In addition, interest expense for the TIR Entities is only reflected for periods from June 26, 2013 forward.

Consolidated Results of Operations

The following table compares the operating results of Cypress Energy Partners, L.P. for the periods indicated.

	2015 (a)	**2014**	**2013 (b)** ***Recast***
	(in thousands)		
Revenues	$371,191	$404,418	$249,133
Costs of services	326,261	355,355	213,690
Gross margin	44,930	49,063	35,443
Operating costs and expense:			

General and administrative	23,795	21,321	12,467
Depreciation, amortization and accretion	5,427	6,345	5,164
Impairments	6,645	32,546	4,131
Operating income (loss)	9,063	(11,149)	13,681
Other income (expense):			
Interest expense, net	(5,656)	(3,208)	(4,000)
Offering costs	-	(446)	(1,376)
Gain on reversal of contingent consideration	-	-	11,250
Gain on waiver of right of purchase and other, net	1,136	92	37
Net income (loss) before income tax expense	4,543	(14,711)	19,592
Income tax expense	452	468	15,237
Net income (loss)	4,091	(15,179)	4,355
Net income attributable to non-controlling interests	599	4,973	22
Net income (loss) attributable to partners / controlling interests	3,492	(20,152)	$4,333
Net income (loss) attributable to general partner	(648)	149	
Net income (loss) attributable to limited partners	$4,140	$(20,301)	

(a) Activity for the year ended December 31, 2015 includes the operations of Brown (IS segment) from the May 1, 2015 acquisition date through the end of the year.

(b) Activity for the year ended December 31, 2013 includes the operations of the TIR Entities (PIS segment) from the June 26, 2013 acquisition date through the end of the year.

See the detailed discussion of revenues, costs of services, gross margin, general and administrative expense and depreciation, amortization and accretion by reportable segment below. See also Note 2 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, 2015, 2014 and 2013.

Interest expense. Interest expense increased in 2015 primarily due to increased borrowings related to the acquisition of the remaining 49.9% interest in the TIR Entities and the acquisition of 51% of Brown. Interest expense in 2015 and 2014 primarily consists of interest on borrowings under our Credit Agreement entered into in December 2013, as well as amortization of debt issuance costs and unused commitment fees. Interest expense declined from 2013 to 2014 primarily due to lower interest rates related to the new credit facility entered into in December 2013, even though interest expense for the TIR Entities only includes periods subsequent to June 26, 2013, the date they were effectively acquired by affiliates of the Company. Average debt outstanding for the years ended December 31, 2015, 2014 and 2013 was $129.9 million, $72.5 million and $62.8 million, respectively. Average outstanding debt for 2013 only includes the period from June 26, 2013 through December 31, 2013 as the Partnership had no debt outside of the TIR Entities.

Offering costs. We incurred costs of $0.4 million and $1.4 million in 2014 and 2013, respectively, primarily for professional services related to our IPO. There were no offering costs incurred in 2015.

Gain on reversal of contingent consideration. During 2013, the W&ES segment recognized a non-recurring gain of $11.3 million as a result of the reversal of a previously recorded contingent purchase price liability.

Income tax expense. We believe that we qualify as a partnership for income tax purposes and therefore, generally do not pay income tax. Rather, each owner reports his or her share of our income or loss on his or her individual tax return. Income tax expense in 2015 and 2014 of $0.5 million includes income taxes related to one taxable corporate subsidiary in the United States and two taxable corporate subsidiaries in Canada in our PIS segment, as well as business activity, gross margin, and franchise taxes incurred in certain states. The 2013 income tax expense of $15.2 million is primarily related to the change in legal status of certain of the TIR Entities, whereby they converted from corporate status to partnership status in December 2013, as well as income tax expense related to taxable corporate subsidiaries of the TIR Entities for the period from June 26, 2013 to December 9, 2013, the date of conversion to pass-through status. The Predecessor did not incur any income taxes.

Gain on waiver of right of purchase and other, net. During 2015, the Partnership received $1.0 million for relinquishing its option to purchase certain assets from a related party. The proceeds from that transaction are recorded in *other, net* in the Consolidated Statement of Operations

Net income attributable to non-controlling interests. The net income attributable to non-controlling interests shown in our Consolidated Results of Operations reflects interests in the net income of consolidated entities that are not 100% owned by the Partnership. The decrease from 2014 to 2015 reflects the fact that we acquired the remaining 49.9% of the TIR Entities effective February 1, 2015. The 2015 balance primarily represents one month of minority ownership of the TIR Entities, as well as eight months of 49% of Brown Integrity, LLC earnings (acquired May 1, 2015). The increase from 2013 reflects the fact that the TIR Entities were reported on a combined basis of accounting from June 26, 2013 through January 21, 2014, the date a 50.1% ownership interest in the TIR Entities was contributed to the Partnership.

Segment Operating Results

Pipeline Inspection Services (PIS)

The following table summarizes the operating results of our PIS segment for the years ended December 31, 2015 and 2014.

	Years Ended December 31,					
	2015	% of Revenue	2014	% of Revenue	Change	% Change
	(in thousands, except average revenue and inspector data)					
Revenue	$341,929		$382,002		$(40,073)	(10.5)%
Costs of services	309,584		346,738		(37,154)	(10.7)%
Gross margin	32,345	9.5%	35,264	9.2%	(2,919)	(8.3)%
General and administrative	16,672	4.9%	17,734	4.6%	(1,062)	(6.0)%
Depreciation, amortization and accretion	2,512	0.7%	2,539	0.7%	(27)	(1.1)%
Operating income	$13,161	3.8%	$14,991	3.9%	$(1,830)	(12.2)%
Operating Data						
Average number of inspectors	1,392		1,535		(143)	
Average revenue per inspector per week	$4,711		$4,773		$(62)	
Revenue variance due to number of inspectors					$(35,126)	
Revenue variance due to average revenue per inspector					$(4,947)	

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Revenues. Revenues decreased $40.1 million from 2014 to 2015 primarily due to a decrease in the average number of inspectors engaged (down 143 inspectors accounting for $35.1 million of the decrease from year-to-year) and, to a lesser extent, a reduction in the average revenue billed for each inspector during the years presented. The decline in the average number of inspectors deployed is directly attributable to the timing of projects for our customers. During 2015 we have seen delays and/or cancellations of significant projects within our customer base as a result of economic conditions in the energy industry. We continue to focus on areas of inspection less impacted by economic conditions, such as maintenance projects and projects associated with public utility companies to help mitigate the decline in revenues associated with new constructions projects. The decline in average revenue per inspector is impacted by a change in customer mix as well as pricing concessions granted during the year. Fluctuations in the average revenue per inspector per year are not unexpected given our mix of customers as we have different billing rates and charges for different types of inspectors and different types of inspection services.

Costs of services. Costs of services decreased $37.2 million from 2014 to 2015, which is directly attributable to the decline in revenues and average number of inspectors in the field.

Gross margin. Gross margin decreased $2.9 million from 2014 to 2015. The gross margin percentages from year-to-year improved slightly (9.5% in 2015 and 9.2% in 2014). The increase in gross margin is attributable to the mix of services provided throughout the year.

General and administrative. General and administrative expenses decreased $1.1 million primarily due to focused efforts to reduce overhead costs, primarily non-billable payroll, in response to the energy sector downturn.

Operating income. Operating income for the year ended December 31, 2015 decreased $1.8 million compared to the year ended December 31, 2014, primarily due to the gross margin decrease of $2.9 million, offset by a decrease in general and administrative costs of $1.1 million.

The following table summarizes the operating results of our PIS segment for the year ended December 31, 2014 and the period from June 26, 2013 through December 31, 2013.

	Years Ended December 31,					
	2014	**% of Revenue**	**2013 (a)**	**% of Revenue**	**Change**	**% Change**
	(in thousands, except average revenue and inspector data)					
Revenue	$382,002		$226,901		$155,101	68.4%

Costs of services	346,738		206,343		140,395	68.0%
Gross margin	35,264	9.2%	20,558	9.1%	14,706	71.5%
General and administrative	17,734	4.6%	9,175	4.0%	8,559	93.3%
Depreciation, amortization and accretion	2,539	0.7%	1,327	0.6%	1,212	91.3%
Impairments	-	0.0%	702	0.3%	(702)	(100.0)%
Operating income	$14,991	3.9%	$9,354	4.1%	$5,637	60.3%
Operating Data						
Average number of inspectors	1,535		1,706	(b)	(171)	(10.0)%
Average revenue per inspector per week	$4,773		$4,952	(b)	$(179)	(3.6)%

(a) Includes activity from June 26, 2013 acquisition date through December 31, 2013.

(b) Average number of inspectors and average revenue per inspector per week reflect averages over the period since acquisition.

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Revenues. Revenues increased $155.1 million from 2013 to 2014 primarily due to the period ending December 31, 2013 only reflects revenues since the acquisition of the TIR Entities (see note (a) above). The average number of inspectors decreased by 171 between the periods primarily due to seasonality associated with the first and second quarter of 2013. The decline in average revenue per inspector primarily relates to the change in mix of customers as we have different billing rates for different types of inspectors with each customer.

Costs of services. Costs of services increased $140.4 million from 2013 to 2014 primarily due to the fact that 2013 reflects costs of services only since the acquisition of the TIR Entities (see note (a) above).

Gross margin. Gross margin increased $14.7 million from 2013 to 2014 due to a full year of operations in 2014. The 2014 gross margin percentage remained consistent with that of the prior year at just over 9.0%.

General and administrative expense. General and administrative expense increased $8.6 million primarily due to the fact that 2013 reflects expenses only since the acquisition of the TIR Entities.

Depreciation, amortization and accretion. Depreciation and amortization expense increased $1.2 million primarily due to the fact that 2013 reflects expenses only since the acquisition of the TIR Entities.

Impairments. During 2013, the segment recorded impairment charges totaling $0.7 million related to certain intangible assets associated with one of its Canadian entities. There were no impairment charges recorded in 2014.

Operating income. Operating income for the year ended December 31, 2014 increased $5.6 million over the prior year primarily due to the fact that 2013 only reflects revenues and expenses since the acquisition of the TIR Entities.

Integrity Services (IS)

The following table summarizes the results of the IS segment for the period May 1, 2015 (date of acquisition) through December 31, 2015.

	May 1, 2015 through December 31, 2015 Period					
	2015	**% of Revenue**	**2014**	**% of Revenue**	**Change**	**% Change**
	(in thousands, except average revenue and inspector data)					
Revenue	$14,614		$ -		$14,614	
Costs of sales	10,398		-		10,398	
Gross margin	4,216	28.8%	-		4,216	
General and administrative	2,490	17.0%	-		2,490	
Depreciation, amortization and accretion	421	2.9%	-		421	
Operating income	$1,305	8.9%	$ -		$1,305	
Operating Data						
Average number of field personnel	33					
Average revenue per field personnel per week	$20,261					

Revenue. Revenues for the IS segment since the May 1, 2015 acquisition were $14.6 million, representing hydrostatic testing of newly constructed and existing pipelines performed under cost plus and fixed price contracts.

Costs of services. Costs of services were $10.4 million and represent labor, equipment, supplies and other costs necessary to perform the contracted hydrostatic tests.

Gross margin. The gross margin was $4.2 million for the period.

General and administrative. General and administrative costs for the period were $2.5 million and were primarily composed of salaries and general office expenditures.

Depreciation, amortization and accretion. Depreciation and amortization charges for the period were $0.4 million.

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Water and Environmental Services (W&ES)

The following table summarizes the operating results of our W&ES segment for the years ended December 31, 2015 and 2014.

	Years Ended December 31,					
	2015	% of Revenue	2014	% of Revenue	Change	% Change
	(in thousands, except per barrel data)					
Revenue	$14,648		$22,416		$(7,768)	(34.7)%
Costs of services	6,279		8,617		(2,338)	(27.1)%
Gross margin	8,369	57.1%	13,799	61.6%	(5,430)	(39.4)%
General and administrative	3,351	22.9%	3,587	16.0%	(236)	(6.6)%
Depreciation, amortization and accretion	2,494	17.0%	3,806	17.0%	(1,312)	(34.5)%
Impairments	6,645	45.4%	32,546	145.2%	(25,901)	(79.6)%
Operating loss	$(4,121)	(28.1)%	$(26,140)	(116.6)%	$22,019	(84.2)%
Operating Data						
Total barrels of saltwater disposed	18,864		19,066		(202)	(1.1)%
Average revenue per barrel disposed (a)	$0.78		$1.18		$(0.40)	(34.0)%
Revenue variance due to barrels disposed					$(237)	
Revenue variance due to revenue per barrel					$(7,531)	

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

Revenue. The decrease of $7.8 million in revenues is primarily due to a 34.0% reduction in the overall average disposal price per barrel from 2014 to 2015 (accounting for $7.5 million of the total $7.8 million decrease year-to-year). The average revenue per barrel disposed declined from $1.18 in 2014 to $0.78 in 2015. The primary contributor to the decline in the average revenue per barrel is the decline in oil revenues. In 2014, oil revenue represented 22% of total revenue compared to 8% in 2015. The decline in oil revenue is attributable to the decline in oil prices, as well as the volume of oil recovered through our skim oil recovery process. The decline in oil recovered is associated with decreased drilling in the areas in which we operate. Drilling activities generate flowback water which is typically higher in oil content. In addition to the decline in oil revenues, the segment has experienced a corresponding decline in flowback water disposal revenues. The decline in the volume flowback water disposed was largely offset by an increase in production water volumes disposed, primarily attributable to the acquisition of the Mork facility effective December 1, 2014. However, because flowback disposal pricing is higher than production water disposal pricing, we experienced an overall decline in revenue attributable to the shift in volumes between flowback disposal and production disposal.

Costs of services. Costs of services decreased from 2014 to 2015 primarily due to lower repairs and maintenance expenses, lower labor related costs and lower oil disposal costs. Repairs and maintenance expenses can fluctuate period to period depending on the nature and timing of required repairs and the type and volume of water disposed at each facility. The decrease in repairs and maintenance is attributable to lower water volumes, in particular flowback volumes associated with drilling activity, as well as the occurrence of some large expenditures in 2014. In response to lower volumes and prices, we have altered labor schedules and hours of operation across our facilities which has resulted in lower total labor costs. In addition to the schedule adjustments, we are no longer incurring labor costs for two facilities that we previously managed. The lower oil disposal costs are directly attributable to the decline in oil barrels sold.

Gross margin. Gross margin decreased as a result of the reduced revenues, offset by a reduction in cost of services. The decrease in gross margin percentage is mainly caused by lower water disposal revenues, offset in part, by lower costs of services from 2014 to 2015. The decrease in the gross margin percentage is also attributable to the loss of management revenue related to two management contracts terminated by the owners in the first half of 2015.

General and administrative expense. The reduction in general and administrative expenses of $0.2 million is mainly attributable to general cost cutting measures instituted by the Partnership.

Impairments. As a result of the decline in commodity prices and a decline in drilling activity around some of our facilities, we recorded impairment charges during the years ended December 31, 2015 and 2014 associated with our W&ES segment totaling $6.6 million and $32.5 million, respectively. The impairment charges consist of impairments of long lived assets in the years ended December 31, 2015 and 2014 totaling $6.6 million and $12.8 million, respectively, and goodwill impairments in the year ended December 31, 2014 totaling $19.8 million.

Operating loss. Operating loss declined $22.0 million from 2014 to 2015 primarily due to a decrease in impairment charges totaling $25.9 million. Excluding the impairment charges, segment operating loss increased $3.9 million primarily attributable to the decline in the gross margin discussed above, offset in part, by lower depreciation, amortization and accretion deductions due to the impairment write down to the basis of depreciable assets in 2014.

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The following table summarizes the operating results of our W&ES segment for the years ended December 31, 2014 and 2013.

	Years Ended December 31,					
	2014	% of Revenue	2013 (Recast)	% of Revenue	Change	% Change
	(in thousands, except per barrel data)					
Revenue	$22,416		$22,232		$184	0.8%
Costs of services	8,617		7,347		1,270	17.3%
Gross margin	13,799	61.6%	14,885	67.0%	(1,086)	(7.3)%
General and administrative	3,587	16.0%	3,292	14.8%	295	9.0%
Depreciation, amortization and accretion	3,806	17.0%	3,837	17.3%	(31)	(0.8)%
Impairments	32,546	145.2%	3,429	15.4%	29,117	849.1%
Operating income (loss)	$(26,140)	(116.6)%	$4,327	19.5%	$(30,467)	(704.1)%
Operating Data						
Total barrels of saltwater disposed	19,066		19,541		(475)	(2.4)%
Average revenue per barrel disposed (a)	$1.18		$1.14		$0.04	3.3%
Revenue variance due to barrels disposed					$(541)	
Revenue variance due to revenue per barrel					$725	

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

Revenue. The increase of $0.2 million in revenues is primarily due to a $0.7 million positive price variance as the average revenue per barrel disposed increased from $1.14 in 2013 to $1.18 in 2014. This increase was partially offset by a $0.5 million negative volume variance as water volumes disposed decreased from 19.5 million barrels in 2013 to 19.1 million barrels in 2014. The increase in average revenue per barrel disposed is due primarily to higher management fee revenues associated with a full year of operations of CES LLC which was acquired effective December 1, 2013.

Costs of services. Costs of services increased from 2013 to 2014 due primarily to increased repairs and maintenance expenses related to higher periodic required expenditures as the wells age. These expenditures primarily include pump repairs and clean out of oil storage and separation tanks.

Gross margin. The decrease in gross margin is mainly caused by higher repair and maintenance expenses in 2014.

General and administrative expense. The increase in general and administrative expense is primarily attributable to the allocation of the annual administration fee charged by Holdings under our amended and restated omnibus agreement. The allocation to W&ES for 2014 was $1.1 million, which exceeded 2013 allocated costs by $0.6 million. In addition, general and administrative expenses increased $0.2 million as a result of having a full year of operations of CES LLC. The increases were partially offset by a reduction of professional service fees of $0.6 million. The decrease in professional service fees were primarily related to the preparation of our IPO in 2013 that were absent in 2014.

Impairments. As a result of the decline in commodity prices and a decline in drilling activity around some of our facilities, we recorded impairment charges during the year ended December 31, 2014 associated with our W&ES segment totaling $32.5 million. The impairment charge consists of impairments of long lived assets totaling $12.8 million and goodwill impairments totaling $19.8 million. During the year ended December 31, 2013, we recorded an impairment charge at one of our SWD facilities totaling $3.4 million.

Operating income (loss). Operating income declined $30.5 million from 2013 primarily due to an increase in impairment charges totaling $29.1 million. Excluding the impairment charges, segment operating income decreased $1.4 million.

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Liquidity and Capital Resources

We anticipate making growth capital expenditures in the future, including acquiring new pipeline inspection companies and SWD facilities or expanding our existing assets and offerings in our current operations. In addition, the working capital needs of the PIS segment are substantial. Please read *"Risk Factors — Risks Related to Our Business — The working capital needs of the PIS 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 borrowings under our Credit Agreement 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, 2015, our sources of liquidity included:

- cash generated from operations, which resulted in $24.2 million in cash on the balance sheet at December 31, 2015 (inclusive of cash attributable to the non-controlling interest holders);

- borrowings under our Credit Agreement under which we had $59.1 million available for borrowings at December 31, 2015 that are limited by certain borrowing base limitations and financial covenant ratios as outlined in the Credit Agreement; and

- issuance of equity and/or debt securities. The Partnership filed a Securities Registration Statement with the Securities and Exchange Commission on June 8, 2015 to register $1.0 billion in securities, which the Partnership may issue in any combination of equity or debt securities from time to time in one or more offerings.

We believe that the cash generated from our current sources of liquidity will be sufficient to allow us to meet the minimum quarterly distributions as outlined in our partnership agreement, working capital requirements and capital expenditures for the foreseeable future.

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. The cash flows include activity of the W&ES segment for the periods presented and activity of the PIS segment since the acquisition of the TIR Entities on June 26, 2013 and activity of the IS segment since the acquisition of Brown on May 1, 2015 and therefore, may not be comparable from period to period.

	Year Ended December 31,		
	2015	**2014**	**2013**
			Recast
		(in thousands)	
Net cash provided by operating activities	$26,921	$ 13,016	$7,154
Net cash provided by (used in) investing activities	(64,879)	(2,286)	5,779
Net cash provided by (used in) financing activities	42,501	(16,030)	13,363
Effect of exchange rates on cash	(1,150)	(633)	(90)
Net increase (decrease) in cash and cash equivalents	$3,393	$ (5,933)	$26,206

Operating activities. Operating cash flow increased in 2015 because of the fact that the operating cash flows for 2014 reflect the payment of income taxes of approximately $15.0 related to the conversion of the U.S. TIR Entities from taxable entities to pass-through entities for income tax purposes. Income taxes reflected in the 2015 cash flows are minimal. The increase from 2013 to 2014 is a result of the fact that 2013 only includes operations of the TIR Entities form Junes 26, 2013 forward.

Investing activities. The cash used in investing activities in 2015 primarily relates to the acquisition of the remainder of the TIR Entities effective February 1, 2015 for $52.6 million and the acquisition of Brown on May 1, 2015 for $10.4 million. There was only one acquisition in 2014 for a total of $1.7 million. The remaining investing cash flows for 2015 and 2014 were primarily for capital expenditures at facilities. The cash provided by investing activities in 2013 represents $10.8 million of cash on the balance sheet of the TIR Entities at June 26, 2013, offset primarily by capital expenditures at our facilities.

Financing activities. For the year ended December 31, 2015, cash flows from financing activities primarily consist of incremental borrowings under our revolving credit facility of $68.8 million offset by repayments of $5.5 million and distributions to partners and non-controlling members totaling $10.8 million. The incremental borrowings included $52.6 million for the TIR Entities acquisition and $10.7 million for the acquisition of Brown. For the year ended December 31, 2014, net activity under our credit facility was attributable to incremental borrowings of $2.6 million related to the acquisition and completion of an additional SWD facility. In addition, distributions to partners and the non-controlling members of the TIR Entities totaled $17.7 million. Also included in our financial cash flows for 2014 were proceeds from our IPO of $80.2 million which were distributed to Holdings. Cash flows from financing activities for 2013 included $18.9 million of net borrowings under our financing arrangements, offset by payment of $3.4 in debt issuance costs and $2.5 million in offering costs associated with our IPO.

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Working Capital

Our working capital was $64.2 million at December 31, 2015, compared to $66.0 million at December 31, 2014. Our PIS and IS 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. We utilize borrowings under our Credit Agreement to fund the working capital needs of these segments. These borrowings reduce the amount of credit available for other uses, such as acquisitions and growth projects, and increases interest expense, thereby reducing cash flow. Please read *"Risk Factors — Risks Related to Our Business — The working capital needs of the PIS 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."*

Capital Requirements

W&ES has capital needs requiring investment for the maintenance of existing SWD facilities and the acquisition or construction and development of new SWD facilities. Our partnership agreement will require 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 tankage, workovers, pipelines, pumps and other improvement of existing capital assets, including the construction or development of new capital assets to replace our existing saltwater disposal systems as they become obsolete. Other examples of maintenance capital expenditures are expenditures to repair, refurbish and replace tubing and packers on the SWD well itself to maintain equipment reliability, integrity and safety, as well as to address environmental laws and regulations. Maintenance capital expenditures for the years ended December 31, 2015 and 2014 were $0.5 million and $0.2 million, 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 from Holdings or third-parties and the construction or development of additional saltwater disposal capacity or efficiencies, to the extent such expenditures are expected to expand our long-term operating capacity or operating income. Expansion capital expenditures include interest payments (and related fees) on debt incurred to finance all or a portion of expansion capital expenditures in respect of the period from the date that we enter into a binding obligation to commence the construction, development, replacement, improvement, automation or expansion of a capital asset and ending on the earlier to occur of the date that such capital improvement commences commercial service and the date that such capital improvement is abandoned or disposed of. Expansion capital expenditures for the years ended December 31, 2015 and 2014 were $1.2 million and $1.8 million, respectively.

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

Our Credit Agreement

The Partnership is party to a credit agreement (as amended, the "Credit Agreement") that provides up to $200.0 million in borrowing capacity, subject to certain limitations. The Credit Agreement includes a working capital revolving credit facility ("WCRCF") which provides up to $75.0 million in borrowing capacity to fund working capital needs and an acquisition revolving credit facility ("ARCF") which provides up to $125.0 million in borrowing capacity to fund acquisitions and expansion projects. In addition, the Credit Agreement provides for an accordion feature that allows us to increase the availability under the facilities by an additional $125.0 million. The Credit Agreement matures December 24, 2018.

At December 31, 2015 and 2014, outstanding borrowings under the Credit Agreement totaled $140.9 million and $77.6 million, respectively. Borrowings under the WCRCF totaled $52.0 and $50.0 million at December 31, 2015 and 2014, respectively. Borrowings under the WCRCF are limited by a monthly borrowing base calculation as defined in the Credit Agreement. If, at any time, outstanding borrowings under the WCRCF exceed the Partnership's calculated borrowing base, principal in the amount of the excess is due upon submission of the borrowing base calculation. Borrowings under the ARCF totaled $88.9 million and $27.6 million at December 31, 2015 and 2014, respectively. Available borrowings under the ARCF may be limited by certain financial covenant ratios as defined in the agreement. The obligations under our Credit Agreement are secured by a first priority lien on substantially all assets of the Partnership.

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 1.25% to 2.75% per annum ("Base Rate Borrowing") or (ii) an adjusted LIBOR rate plus a margin of 2.25% to 3.75% 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 Credit Agreement borrowings ranged between 2.68% and 4.17% for the year ended December 31, 2015 and 2.65% and 3.50% for the year ended December 31, 2014. 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. Interest paid during the years ended December 31, 2015 and 2014 was $5.2 million and $3.1 million, respectively, including commitment fees.

Our Credit Agreement contains various customary affirmative and negative covenants and restrictive provisions. Our Credit Agreement also requires maintenance of certain financial covenants, including a combined total adjusted leverage ratio (as defined in our Credit Agreement) of not more than 4.0 to 1.0 and an interest coverage ratio (as defined in our Credit Agreement) of not less than 3.0 to 1.0. At December 31, 2015, our total adjusted leverage ratio was 3.07 to 1.0 and our interest coverage ratio was 4.84 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 our Credit Agreement, the lenders may declare any outstanding principal of our Credit Agreement debt, together with accrued and unpaid interest, to be immediately due and payable and may exercise the other remedies set forth or referred to in our Credit Agreement. We expect to remain in compliance with all of our financial debt covenants throughout the next twelve months.

In addition, our Credit Agreement restricts our ability to make distributions on, or redeem or repurchase, our equity interests. 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 our Credit Agreement, the borrowers and the guarantors are in compliance with the financial covenants, the borrowing base (which includes 100% of cash on hand) exceeds the amount of outstanding credit extensions under the WCRCF by at least $5.0 million and at least $5.0 million in lender commitments are available to be drawn under the WCRCF.

On May 4, 2015, the Partnership and the Partnership's lenders entered into Amendment No. 2 to the Credit Agreement ("Amendment"), which amended the Credit Agreement to, among other matters, (i) allow each of Tulsa Inspection Resources – Canada ULC and Foley Inspection Services ULC to join the Credit Agreement as an additional borrower under the Credit Agreement, and (ii) amend certain other provisions of the Credit Agreement as more specifically set forth in the Amendment.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Contractual Obligations

A summary of the Partnership's contractual obligations and other commitments, as of December 31, 2015, is shown in the table below.

	Total	Less Than 1 Year	1 - 3 Years	3 - 5 Years	More Than 5 Years
			(in thousands)		
Long-term debt	$ 140,900	$ -	$ 140,900	$ -	$ -
Lease obligations	2,161	748	806	77	530
Total	$ 143,061	$ 748	$ 141,706	$ 77	$ 530

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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. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of crude oil in W&ES. Both our profitability and our cash flow are affected by volatility in the prices of these commodities. Crude oil prices are impacted by changes in the supply and demand for crude oil, 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 distributions to unitholders. We do not hedge our exposure to crude oil prices.

Less than 1% of our consolidated revenues in 2015 are 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 of 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, as of December 31, 2015, our exposure consists of floating interest rate fluctuations on our outstanding indebtedness under our Credit Agreement of $140.9 million. A hypothetical change in interest rates of 1.0% would result in an increase or decrease of our annual interest expense of approximately $1.4 million.

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 was evidenced by the Federal Reserve raising interest rates in December 2015. 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. In addition, any downgrade of our customers' receivables from investment grade (defined as BBB- or higher by S&P or Baa3 or higher by Moody's) could reduce our borrowing capacity or potentially place the Partnership at risk of default on the working capital revolving credit facility of our Credit Agreement. The result of downgrades of our customers' receivables could have a material adverse effect on our business, financial condition, results of operations or cash flows.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Cypress Energy Partners, GP, LLC

General Partner of Cypress Energy Partners, L.P.

and the Limited Partners of Cypress Energy Partners, L.P.

We have audited the accompanying consolidated balance sheets of Cypress Energy Partners, L.P. (the "Partnership") as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, cash flows, and partners' equity for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Partnership's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, 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. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Cypress Energy Partners, L.P. at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Tulsa, Oklahoma

March 23, 2016

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CYPRESS ENERGY PARTNERS, L.P.

Consolidated Balance Sheets

As of December 31, 2015 and 2014

(in thousands, except unit data)

	December 31, 2015	**December 31, 2014**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 24,150	$ 20,757
Trade accounts receivable, net	48,265	54,075
Deferred tax assets	34	68
Prepaid expenses and other	2,329	2,440
Total current assets	74,778	77,340
Property and equipment:		
Property and equipment, at cost	23,706	27,878
Less: Accumulated depreciation	5,369	3,538
Total property and equipment, net	18,337	24,340
Intangible assets, net	32,486	30,245
Goodwill	65,273	55,545
Debt issuance costs, net	1,771	2,318
Other assets	42	54
Total assets	$ 192,687	$ 189,842
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable	$ 2,205	$ 2,461
Accounts payable - affiliates	913	586
Accrued payroll and other	7,095	7,750
Deferred tax liabilities	42	-
Income taxes payable	350	546
Total current liabilities	10,605	11,343
Long-term debt	140,900	77,600
Deferred tax liabilities	363	438
Asset retirement obligations	117	33
Total liabilities	151,985	89,414
Commitments and contingencies - Note 13		
Owners' equity:		
Partners’ capital:		

Common units (5,920,467 and 5,913,000 units outstanding at December 31, 2015 and 2014, respectively)	253	6,285
Subordinated units (5,913,000 units outstanding at December 31, 2015 and 2014)	59,143	66,096
General partner	(25,876)	1,999
Accumulated other comprehensive loss	(2,791)	(525)
Total partners' capital	30,729	73,855
Non-controlling interests	9,973	26,573
Total owners' equity	40,702	100,428
Total liabilities and owners' equity	$ 192,687	$ 189,842

See accompanying notes.

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CYPRESS ENERGY PARTNERS, L.P.

Consolidated Statements of Operations

For the Years Ended December 31, 2015, 2014 and 2013

(in thousands, except unit and per unit data)

	2015	2014	2013 *Recast - Note 2*
Revenues	$371,191	$404,418	$249,133
Costs of services	326,261	355,355	213,690
Gross margin	44,930	49,063	35,443
Operating costs and expense:			
General and administrative	23,795	21,321	12,467
Depreciation, amortization and accretion	5,427	6,345	5,164
Impairments	6,645	32,546	4,131
Operating income (loss)	9,063	(11,149)	13,681
Other (expense) income:			
Interest expense, net	(5,656)	(3,208)	(4,000)
Offering costs	-	(446)	(1,376)
Gain on reversal of contingent consideration	-	-	11,250
Gain on waiver of right of purchase and other, net	1,136	92	37
Net income (loss) before income tax expense	4,543	(14,711)	19,592
Income tax expense	452	468	15,237
Net income (loss)	4,091	(15,179)	4,355
Net income attributable to non-controlling interests	599	4,973	22
Net income (loss) attributable to partners / controlling interests	3,492	(20,152)	$4,333
Net income (loss) attributable to general partner	(648)	149	
Net income (loss) attributable to limited partners	$4,140	$(20,301)	
Net income (loss) attributable to limited partners allocated to:			
Common unitholders	$2,071	$(10,150)	
Subordinated unitholders	2,069	(10,151)	
	$4,140	$(20,301)	
Net income (loss) per common limited partner unit - basic and diluted	$0.35	$(1.72)	
Net income (loss) per subordinated limited partner unit - basic and diluted	$0.35	$(1.72)	

Weighted average common units outstanding - basic and diluted	5,918,608	5,913,000
Weighted average subordinated units outstanding - basic and diluted	5,913,000	5,913,000

See accompanying notes.

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CYPRESS ENERGY PARTNERS, L.P.

Consolidated Statements of Comprehensive Income (Loss)

For the Years Ended December 31, 2015, 2014 and 2013

(in thousands)

	2015	**2014**	**2013** ***Recast - Note 2***
Net income (loss)	$4,091	$(15,179)	$4,355
Other comprehensive loss - foreign currency translation	(1,742)	(937)	(112)
Comprehensive income (loss)	$2,349	$(16,116)	$4,243
Comprehensive income attributable to non-controlling interests	142	4,658	22
Comprehensive income (loss) attributable to partners / controlling interests	$2,207	$(20,774)	$4,221

See accompanying notes.

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CYPRESS ENERGY PARTNERS, L.P.

Consolidated Statement of Owners' Equity

For the Years Ended December 31, 2015, 2014 and 2013

(in thousands)

			Partners' Capital					
	Parent Net Investment Attributable to Controlling Interest	**Parent Net Investment Attributable to Non-Controlling Interest**	**General Partner**	**Common Units**	**Subordinated Units**	**Accumulated Other Comprehensive Loss**	**Non-controlling Interests**	**Total Owners' Equity**
Balance, December 31, 2012 (Recast - Note 2)	$ 66,497	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contribution attributable to General Partner	-	-	6,210	-	-	-	-	6,210
Sale of member interest in subsidiary	-	697	-	-	-	-	-	-
Net distribution to members	(5,763)	-	-	-	-	-	-	-
Parent investment in TIR Entities	63,617	-	-	-	-	-	-	-
Purchase of non-controlling interests	(572)	-	-	-	-	-	-	-
Stock option expense	90	-	-	-	-	-	-	-
Tax benefit of stock options exercised over FMV	528	-	-	-	-	-	-	-
Net income	5,727	22	(1,394)	-	-	-	-	(1,394)
Foreign currency translation adjustment	(112)	-	-	-	-	-	-	-
Balance, December 31.2013	130,012	719	4,816	-	-	-	-	4,816

(Recast - Note 2)

Net income attributable to the period from January 1, 2014 to January 20, 2014	1,092	(6)	(446)	-	-	-	-	(446)
Foreign currency translation adjustment attributable to the period January 1, 2014 to January 20, 2014	(304)	-	-	-	-	-	-	-
Net distributions to members	(168)	-	-	-	-	-	-	-
Contribution attributable to General Partner	-	-	979	-	-	-	-	979
Contributions of Predecessor and 50.1% of TIR Entities in exchange for units	(130,632)	(713)	-	22,491	82,470	(208)	26,592	131,345
Proceeds from initial public offering, net of costs	-	-	(2,853)	80,213	-	-	-	77,360
Distribution of initial public offering proceeds to Cypress Energy Holdings, LLC	-	-	-	(80,213)	-	-	-	(80,213)
Distribution to limited partners	-	-	-	(6,532)	(6,532)	-	-	(13,064)
Distributions to non-controlling interest	-	-	-	-	-	-	(4,683)	(4,683)
Equity-based compensation	-	-	-	476	309	-	-	785
Net income attributable to the period from January 21, 2014 to December 31, 2014	-	-	(497)	(10,150)	(10,151)	-	4,979	(15,819)
Foreign currency translation adjustment	-	-	-	-	-	(317)	(315)	(632)
Balance, December 31.2014	-	-	1,999	6,285	66,096	(525)	26,573	100,428

Net income (loss)	-	-	(648)	2,071	2,069	-	599	4,091
Foreign currency translation adjustment	-	-	-	-	-	(1,285)	(457)	(1,742)
Acquisition of 49.9% interest in the TIR Entities (Note 3)	-	-	(27,729)	-	-	(981)	(23,878)	(52,588)
Acquisition of 51% interest in Brown Integrity, LLC (Note 3)	-	-	-	-	-	-	9,497	9,497
Acquisition of 49% interest in Cypress Energy Services, LLC (Note 12)	-	-	-	470	470	-	(940)	-
Contribution attributable to General Partner	-	-	648	-	-	-	-	648
Distributions to limited partners	-	-	-	(9,620)	(9,612)	-	-	(19,232)
Distributions to non-controlling interests	-	-	(146)	-	-	-	(1,421)	(1,567)
Equity-based compensation	-	-	-	1,047	120	-	-	1,167
Balance, December 31.2015	$ -	$ -	$ (25,876)	$ 253	$ 59,143	$ (2,791)	$ 9,973	$ 40,702

See accompanying notes.

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CYPRESS ENERGY PARTNERS, L.P.

Consolidated Statements of Cash Flows

For the Years Ended December 31, 2015, 2014 and 2013

(in thousands)

	2015	2014	2013
Operating activities:			
Net income (loss)	$4,091	$(15,179)	$4,355
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, amortization and accretion	6,004	6,513	5,261
Impairments	6,645	32,546	4,131
(Gain) loss on asset disposal	(1)	3	-
Gain on reversal of contingent consideration	-	-	(11,250)
Interest expense from debt issuance cost amortization	547	714	1,219
Amortization of equity-based compensation	1,167	785	90
Equity earnings in investee company	(102)	(46)	(32)
Distributions from investee company	100	55	-
Deferred tax benefit, net	(32)	(13)	(2,016)
Non-cash allocated expenses	648	497	-
Changes in assets and liabilities:			
Trade accounts receivable	9,039	6,650	(8,793)
Prepaid expenses and other	233	(933)	283
Accounts payable and accrued payroll and other	(1,222)	(2,964)	(1,910)
Income taxes payable	(196)	(15,612)	15,816
Net cash provided by operating activities	26,921	13,016	7,154
Investing activities:			
Proceeds from disposals of property and equipment	2	-	-
Cash paid for acquisition of 49.9% interest in the TIR Entities (Note 3)	(52,588)	-	-
Cash paid for acquisition of 51% interest in Brown Integrity, LLC, net of cash acquired (Note 3)	(10,436)	-	-
Cash acquired - acquisition of 50.1% interest in the TIR Entities (Note 3)	-	-	10,108
Acquisitions of businesses	-	(1,769)	(500)
Purchases of property and equipment	(1,857)	(517)	(3,829)
Net cash provided by (used in) investing activities	(64,879)	(2,286)	5,779
Financing activities:			
Proceeds from initial public offering	-	80,213	-
Distribution of initial public offering proceeds to Cypress Energy Holdings, LLC	-	(80,213)	-
Payment of offering costs	-	(314)	(2,539)
Advances on long-term debt	68,800	7,600	75,000

Repayment of long-term debt	(5,500)	(5,000)	(19,385)
Net payments of factoring agreement	-	-	(36,748)
Payment of debt issuance costs	-	(883)	(3,368)
Payments on behalf of affiliates	-	-	(5,763)
Purchase of non-controlling interests	-	-	(572)
Tax benefit of stock options exercised	-	-	528
Distributions to members prior to IPO	-	(168)	-
Contribution attributable to general partner		482	6,210
Distributions to limited partners	(19,232)	(13,064)	-
Distributions to non-controlling members of the TIR Entities	(1,567)	(4,683)	-
Net cash provided by (used in) financing activities	42,501	(16,030)	13,363
Effect of exchange rates on cash	(1,150)	(633)	(90)
Net increase (decrease) in cash and cash equivalents	3,393	(5,933)	26,206
Cash and cash equivalents, beginning of period	20,757	26,690	484
Cash and cash equivalents, end of period	$24,150	$20,757	$26,690
Non-cash items:			
Accounts payable excluded from capital expenditures	$100	$756	$330
Supplemental cash flow disclosures:			
Cash taxes paid	$579	$16,674	$817
Cash interest paid	5,167	2,415	3,917

See accompanying notes.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements

1. Organization and Operations

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 salt water disposal (“SWD”) 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 outstanding 5,920,467 common units were made available to the general public at $20.00 per common unit ($18.70 per common unit, net of underwriting discounts, commissions and fees), which included a 562,500 unit over-allotment option that was exercised by the underwriters. We received net proceeds of $80.2 million from the IPO, after deducting underwriting discounts and structuring fees. The net proceeds from the IPO were distributed to Cypress Energy Holdings II, LLC as reimbursement for certain capital expenditures it incurred with respect to assets contributed to us. The remaining common units and 100% of the subordinated units are constructively owned by affiliates, employees and directors of the Partnership.

Total deferred offering costs of $2.9 million, including costs incurred during the year ended December 31, 2014 of $0.3 million, were charged against the proceeds of the IPO. In addition, the Partnership incurred $0.4 million and $1.4 million of offering costs during the years ended December 31, 2014 and 2013, respectively, that were expensed as incurred. These non-recurring costs are reflected as *offering costs* in the Partnership’s Consolidated Statements of Operations. There were no offering costs incurred in the year ended December 31, 2015.

Our business is organized into the Pipeline Inspection Services (“PIS”), Integrity Services (“IS”) and Water and Environmental Services (“W&ES”) reportable segments. In conjunction with our acquisition of a 51% interest in Brown Integrity, LLC (“Brown”) (see Note 3), we changed our reportable segments during the second quarter of 2015 by adding the IS segment (see Note 14). In addition, the Pipeline Inspection and Integrity Services segment was renamed Pipeline Inspection Services. PIS provides pipeline inspection and other services to energy exploration and production (“E&P”) and mid-stream companies and their vendors throughout the United States and Canada. The inspectors of PIS perform a variety of 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.

IS provides independent integrity services to major natural gas and petroleum pipeline companies, as well as pipeline construction companies located throughout the United States. Field personnel in this segment primarily perform hydrostatic testing on newly constructed and existing natural gas and petroleum pipelines.

W&ES provides services to oil and natural gas producers and trucking companies through its ownership and operation of eight commercial SWD facilities in the Bakken Shale region of the Williston Basin in North Dakota and two in the Permian Basin in Texas. All of the facilities utilize specialized equipment and remote monitoring to minimize downtime and increase efficiency for peak utilization. These facilities also contain oil skimming processes that remove any remaining oil from water delivered to the sites. In addition to these SWD facilities, we provide management and staffing services for a third-party SWD facility pursuant to a management agreement (see Note 12). We also own a 25% member interest in the managed well.

2. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The financial information for periods prior to the IPO have been recast to reflect the conveyance of Cypress Energy Partners, LLC ("CEP LLC") and a 50.1% ownership interest in Tulsa Inspection Resources, LLC ("TIR LLC"), Tulsa Inspection Resources – Nondestructive Examination, LLC ("TIR NDE") and Tulsa Inspection Resources Holdings, LLC ("TIR Holdings") (collectively the "TIR Entities") to the Partnership at the closing of our IPO, as if the contribution of CEP LLC had occurred as of March 15, 2012, the inception date of CEP LLC, and the contribution of the TIR Entities had occurred as of June 26, 2013, as Cypress Energy Holdings, LLC ("Holdings") and its affiliates did not acquire a controlling interest in the TIR Entities until June 26, 2013. All significant intercompany transactions and account balances have been eliminated. We have made certain reclassifications to the prior period financial statements to conform with classification methods used in the current fiscal year. These reclassifications had no impact on previously reported amounts of total assets, total liabilities, owners' equity, or net income.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

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. Such adjustments consist only of normal recurring items, unless otherwise disclosed herein.

Principles of Consolidation

The Consolidated Financial Statements include all accounts of the Partnership. All intercompany accounts and transactions have been eliminated in consolidation.

Use of Estimates in the Preparation of Financial Statements

The preparation of the Partnership's Consolidated 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 goodwill, intangible assets, property and equipment, the determination of fair values associated with the allocation of purchase price in business combinations, and future asset retirement obligations. Certain estimates are inherently imprecise and may change as future information becomes available. Judgments and assumptions used in the Partnership's estimate of future cash flows and an asset's fair value include such matters as the estimation of oil and gas drilling and producing volumes in the markets served, risks associated with the different geological formation zones into which salt water is disposed, expected future disposal rates and commodity prices, capital expenditures, operating costs and appropriate discount rates. 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 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.

Contributions Attributable to General Partner

During 2013, entities affiliated with Cypress Energy Partners, GP, LLC, (“General Partner”) incurred $6.2 million of costs associated with our initial public offering and our Credit Agreement. These costs were transferred to the Partnership as offering costs, deferred offering costs and/or debt issuance costs and have been recorded as contributions to the Partnership.

During 2015 and 2014, Holdings incurred allocated overhead expenses on behalf of the Partnership totaling $0.6 million and $0.5 million, respectively. These costs represent amounts incurred by Holdings in excess of amounts charged under our amended and restated omnibus agreement. These expenses are reflected as *general and administrative* in the Consolidated Statements of Operations for the years ended December 31, 2015 and 2014 and as *contributions attributable to General Partner* in the Consolidated Statement of Owners' Equity.

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, 2015, U.S. cash balances are insured by the Federal Deposit Insurance Corporation (FDIC) up to $250 thousand per financial institution. Canadian cash balances are insured by the Canada Deposit Insurance Corporation (CDIC) up to $100 thousand per financial institution. At times, cash balances may be in excess of the FDIC or CDIC insurance limits. We periodically assess the financial condition of the institutions where we deposit funds, and for the years ended December 31, 2015 and 2014, we believe our credit risk related to these funds was minimal.

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Notes to Consolidated Financial Statements - Continued

Property and Equipment

Property and equipment consist of land, land improvements, buildings, facilities, wells and equipment, computer and office equipment, and vehicles. The Partnership records 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. Depreciation for these assets is computed using the straight-line method over estimated useful lives. Upon retirement, impairment or disposition of assets, the costs and related accumulated depreciation are removed from the accounts with the resulting gain or losses, if any, reflected in the Consolidated Statements of Operations.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Debt Issuance Costs

Debt issuance costs represent fees and expenses associated with securing the Partnership's Credit Agreement (see Note 7). Amortization of the capitalized debt issuance costs is computed using the effective interest method over the remaining estimated life 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 the net income of the Partnership is generally borne by the individual partners. Net income for financial statement purposes may differ significantly from taxable income 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 partners' tax attributes in us is not available to us.

On December 9, 2013, the TIR Entities converted from corporate status to pass-through entities for U.S. federal income tax purposes. The Partnership recorded tax expense of $15.0 million for income taxes associated with the gain on this conversion in the year ended December 31, 2013. The TIR Entities that have Canadian activity remain taxable in Canada. In addition, the Partnership owns three subsidiaries, Tulsa Inspection Resources – PUC, LLC ("TIR-PUC"), Brown Integrity - PUC, LLC and Cypress Energy Finance Corporation that have elected to be taxed as corporations for U.S. federal income tax purposes. The amounts recognized as income tax expense, income taxes payable, deferred tax assets and deferred tax liabilities on the Consolidated Financial Statements represent the Canadian and U.S. taxes referred to above, as well as partnership-level taxes levied by various states, primarily composed of franchise taxes assessed by the state of Texas.

As a publicly traded limited partnership, we are subject to a statutory requirement that our "qualifying income" (as defined by the Internal Revenue Code, related Treasury Regulations, and Internal Revenue Service pronouncements) exceed 90% of our total gross income, 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. For the year ended December 31, 2014, the year we became a publicly traded limited partnership, and for the year ended December 31, 2015, our income met the statutory qualifying income requirement.

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, 2015, 2014 or 2013. Any interest or penalties would be recognized as a component of income tax expense.

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Notes to Consolidated Financial Statements - Continued

Revenue Recognition

Revenues are recognized when there is persuasive evidence that an arrangement exists, delivery has occurred or services have been rendered, the price is fixed or determinable and collectability is reasonably assured. Water disposal revenues are recognized upon receipt of the wastewater at our disposal facilities. Oil disposal revenues are recognized when delivered to the customer and collectability is reasonably assured. Revenues related to pipeline inspection and integrity services are recognized when the services are provided and collectability is reasonably assured.

Unit-Based Compensation

Our General Partner adopted a long-term incentive plan ("LTIP") in connection with the IPO. The cost of employee services received in exchange for equity instruments is measured based on the grant-date fair value of those instruments. That cost is recognized straight-line over the requisite service period (often the vesting period) as discussed in Note 11.

Net Income Per Unit

We calculate basic net income per limited partner unit for each period by dividing net income by the weighted-average number of limited partner units outstanding. Diluted net income per limited partner unit for each period is the same calculation as basic net income per limited partner unit, except the weighted-average limited partner units outstanding includes the dilutive effect of phantom unit grants associated with our long-term incentive plan.

For the year ended December 31, 2015, there were no dilutive phantom restricted units. For the year ended December 31, 2014, there were 14,520 phantom restricted units; however, as we were in a net loss position, they were excluded from the net income per unit calculation.

Accounts Receivable and Concentration of Credit Risk

We operate in the United States and Canada. We 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 as well as general economic conditions. The Partnership determines accounts receivable allowances based on management's assessment of the creditworthiness of the customers and other collection actions. Trade receivables are written off against the allowance when deemed uncollectible. Recoveries of trade receivables previously written off are recorded when received. The Partnership does not typically charge interest on past due trade receivables and does not require collateral for its trade receivables. The Partnership had an allowance for doubtful accounts of $0.7 million at December 31, 2015 and $0.2 million at December 31, 2014, and recorded bad debt expense of $0.1 million in the years ended December 31, 2015 and 2014 and $0.4 million for the year ended December 31, 2013, respectively.

We had three customers that each represented more than 10% of total accounts receivable as of December 31, 2015 and two customers that each represented more than 10% of total accounts receivable as of December 31, 2014. If one or more of these customers were to default on their payment obligations, we may not be able to replace any of these customers in a timely fashion, on favorable terms, or at all. In addition, any downgrade of our customers' receivables from investment grade (defined as BBB- or higher by S&P or Baa3 or higher by Moody's) could reduce our borrowing capacity or potentially place the Partnership at risk of default on the working capital revolving credit facility of our Credit Agreement. The result of downgrades of our customers' receivables could have a material adverse effect on our business, financial condition, results of operations or cash flows.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Fair Value of Financial Instruments

The carrying amounts reported in the Consolidated Balance Sheets for cash and cash equivalents, trade accounts receivable, prepaid expenses and other, accounts payable, accounts payable – affiliates, accrued payroll and other and income taxes payable approximate their fair values.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in the Partnership's Consolidated Balance Sheets. The following methods and assumptions were used to estimate the fair values:

Impairments of Property and Equipment

The Partnership reviews its property and equipment for impairment whenever events or changes in circumstances indicate, in the judgment of management, that a decline in the recoverability of their carrying value may have occurred. When an indicator of impairment has occurred, the Partnership compares its estimate of undiscounted cash flows attributable to the assets to the carrying value of the assets to determine whether an impairment has occurred. If the estimate of undiscounted cash flows is less than the carrying value of the asset group, the Partnership determines the amount of the impairment recognized in the financial statements by estimating the fair value of the assets using a discounted cash flow model and records a loss for the amount by which the carrying value exceeds the estimated fair value. Assets are grouped for impairment purposes at each SWD facility, which includes the well and supporting well equipment and infrastructure, as this represents the lowest level of cash flows associated with the asset group. The Partnership recorded impairment losses of $6.6 million, $12.8 and $3.4 million for the years ended December 31, 2015, 2014 and 2013, respectively (see Note 4). Additionally, further unfavorable changes in the future are reasonably possible, and therefore, it is possible that we may incur additional impairment charges in the near future.

Goodwill

At December 31, 2015 and 2014, the Partnership had $65.3 and $55.5 million of goodwill, respectively. Goodwill is not amortized, but, is subject to annual reviews on November 1 for impairment at a reporting unit level. The reporting unit or units used to evaluate and measure goodwill for impairment are determined primarily from the manner in which the business is managed or operated. A reporting unit is an operating segment or a component that is one level below an operating segment. In accordance with ASC 350 "*Intangibles — Goodwill and Other*", we have assessed the reporting unit definitions and determined that at December 31, 2015, PIS, IS and W&ES and at December 31, 2014, PIS and W&ES are the appropriate reporting units for testing goodwill impairment. The accounting estimate relative to assessing the impairment of goodwill is a critical accounting estimate for each of our reporting segments.

For our PIS and IS reporting units, we performed qualitative assessments to determine whether the fair values of the reporting units were less than their respective carrying values. Our evaluations consisted of assessing various qualitative factors including current and projected future earnings, capitalization, current customer relationships and projects and the impact of lower crude oil prices on our earnings. The qualitative assessment on these reporting units indicated that there was no need to conduct further quantitative testing for goodwill impairment, nor did our analysis indicate the reporting units were at risk for a potential goodwill impairment. Different judgments from those we used in our qualitative analysis could result in the requirement to perform a quantitative goodwill impairment analysis.

For our W&ES segment, after giving consideration to certain qualitative factors, including trends in the energy industry and recorded impairments of property and equipment, we elected to perform a quantitative goodwill impairment analysis. We computed the fair value of the reporting unit employing multiple valuation methodologies, including a market approach (market price multiples of comparable companies) and an income approach (discounted cash flow analysis). This approach is consistent with the requirement to utilize all appropriate valuation techniques as described in ASC 820-10-35-24 "*Fair Value Measurements and Disclosures.*" Given recent declines in the price of crude oil and the related impact on the valuations of energy related companies, relevant market data was difficult to obtain and was of limited usefulness. Accordingly, we relied heavily on the use of the income approach for the valuation of the reporting unit.

Based on our valuation, we determined that goodwill was not impaired as of our 2015 measurement date. During 2014, we determined that the carrying value of the W&ES reporting unit exceeded the fair value of the reporting unit resulting in a goodwill impairment charge of $19.8 million. The W&ES segment has experienced increased competition in the regions in which we operate, which has resulted in declining volumes and increased pricing pressures. The steady and continued decline in oil prices has intensified competitive pressures and has had a direct impact on our revenues. Many of our customers have announced significantly reduced drilling programs in the areas in which we operate. The decline in drilling will directly impact the amount of flowback and produced water that we process and dispose. The energy downturn is also expected to continue to negatively impact our pricing as our customers look for ways to reduce costs. In addition, as we process lower water volumes, in particular flowback water volumes directly attributable to drilling, we will recover less skim oil. Further unfavorable changes in the future are reasonably possible, and therefore, it is possible that we may incur additional impairment charges in the near future.

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CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Intangible Assets

Intangible assets represent acquired customer relationships, trade names, and certain other intangibles acquired via various acquisitions and have been recorded utilizing various assumptions to determine fair market value including, but not limited to, replacement costs, liquidation values, future cash flows on a discounted basis of the net assets acquired, pay-off values, and average royalty rates. Due to the unobservable nature of these assumptions, these fair value measurements are considered to be Level 3 fair value estimates. Amortization of intangible assets is computed utilizing the straight-line method over their estimated useful lives, typically 5 – 20 years.

We review our intangible assets for impairment whenever events or changes in circumstances indicate we should assess the recoverability of the carrying amount of the intangible asset. We recognized no impairments for other intangible assets in 2015 or 2014. During 2013, the Partnership determined that one of its trade names in PIS had been impaired and identified that the fair value of the trade name, using an undiscounted cash flow model, was less than its carrying amount. A $0.7 million adjustment was made to reduce the carrying value of the trade name to its fair value. The fair value was calculated using a discounted cash flow model applied to the expected royalty values generated from the use of the trade name. Management estimates of the future royalties associated with the use of the trade name were based on forecasted total revenues. Actual results could vary materially from these estimates, which could have a further impact on the fair value of the trade name.

Should we continue to experience a prolonged energy market down turn resulting in further declines in revenues and cash flows, we could incur additional impairment charges associated with our W&ES property and equipment, goodwill or intangible assets.

Non-controlling Interest

The non-controlling interests shown in our Consolidated Financial Statements reflect interests in consolidated entities that are not 100% owned by us as outlined in the appropriate GAAP accounting principles.

Business Combinations

The Partnership evaluates all potential acquisitions and changes in control to determine whether it has purchased or acquired control of a business. If the acquired or newly controlled assets meet the definition of a business, the transaction is accounted for as a business combination; otherwise it is accounted for as an asset acquisition. Transactions discussed in Note 3 were accounted for as business combinations for the periods described.

Foreign Currency Translation

The reporting currency is the U.S. dollar. Non-U.S. dollar denominated monetary items are translated into U.S. dollars at the rate of exchange in effect at the balance sheet date. Non-U.S. dollar denominated non-monetary items are translated to U.S. dollars at the exchange rate in effect when the transactions occur. Revenues and expenses denominated in foreign currencies are translated at the exchange rate in effect during the period. Foreign exchange gains or losses on translation are included in other comprehensive income.

New Accounting Standards

The Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-02 – *Leases* in February 2016. This guidance was proposed in an attempt to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The main difference between previous GAAP and this new guidance is the recognition on the Consolidated Balance Sheets lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. The amendments in this ASU are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application is permitted. We will examine the guidance provided in the ASU and determine the impact this guidance will have on our Consolidated Financial Statements.

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Notes to Consolidated Financial Statements

The FASB issued ASU 2015-17 – *Income Taxes* in November 2105. ASU 2015-17 was issued as a part of the FASB's initiative to reduce complexity in accounting standards. Current GAAP requires an entity to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified consolidated balance sheet. To simplify the presentation of deferred income taxes, this amendment requires that deferred tax liabilities and assets be classified as noncurrent in a classified consolidated balance sheet. Effectively, this will require the Partnership to reclassify current deferred tax liabilities and assets to the noncurrent section of its classified Consolidated Balance Sheets. This ASU is effective for annual and interim periods beginning after December 15, 2016 with earlier application permitted as of the beginning of an annual reporting period.

Business Combinations – ASU 2015-16 was issued by the FASB in September 2015. Essentially, the amendments in the ASU require that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. This will require the Partnership to disclose, by line item, current period earnings adjustments to amounts that otherwise would have been recorded in previous reporting periods as if the adjustment(s) had been recognized as of the acquisition date beginning with fiscal periods after December 15, 2015.

In June 2015, the FASB issued ASU 2015-10 – *Technical Corrections and Improvements*. The amendments in this update represent changes to clarify the Accounting Standards Codification ("ASC"), or make minor improvements to the ASC that are not expected to have a significant effect on current accounting practice or create a significant administrative cost to the Partnership. Specifically as it relates to the Partnership, for nonrecurring fair value measurements estimated at a date during the reporting period other than the end of the reporting period, we are required to clearly indicate that the fair value information presented is not as of the period's end, as well as the date or period that the measurement was determined. The effective date of this guidance varies based on the amendments in the ASU, however, the fair value portion of the ASU referred to above was effective upon its issuance.

The FASB issued ASU 2015-06 – *Earnings Per Share* in April 2015. The amendments in this update specify that for purposes of calculating historical earnings per unit under the two-class method, the earnings (losses) of a transferred business before the date of a dropdown transaction should be allocated entirely to the general partner. The amendments should be applied retrospectively for all financial statements presented. This ASU will be effective for fiscal and interim periods beginning after December 15, 2015. The Partnership does not anticipate that the adoption of this ASU will materially impact our financial position, results of operations or cash flows.

The FASB issued ASU 2015-03 – *Interest – Imputation of Interest* in April 2015. This guidance requires debt issuance costs related to our long-term debt (currently reflected as a non-current asset) to be presented on the balance sheet as a reduction of the carrying amount of the long-term debt. The Partnership will be required to comply with this ASU beginning in 2016. It requires retrospective application and we plan to adopt this guidance beginning in the first quarter of 2016. Generally, the Partnership will be required to offset the *debt issuance costs, net* asset currently reflected as a non-current asset against the long-term debt on the Consolidated Balance Sheets. This will have the effect of reducing both *total assets* and *total liabilities* by the *debt issuance costs, net* amount.

The FASB issued ASU 2014-09 – *Revenue from Contracts with Customers* in May 2014. ASU 2014-09 is intended to clarify the principles for recognizing revenue and develop a common standard for recognizing revenue for GAAP and International Financial Reporting Standards that is applicable to all organizations. In August 2015, the FASB issued ASU 2015-14, *Revenue from Contracts with Customers – Deferral of the Effective Date*, delaying the effective date to implement this guidance for the Partnership to 2018. We are currently evaluating the impact of this ASU on the Partnership. We do not anticipate that the adoption of this ASU will materially impact our financial position, results of operations or cash flows.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

3. Business Combinations

2015 Business Combinations

Brown Integrity, LLC

On May 6, 2015, the Partnership acquired a 51% interest in Brown, a pipeline integrity services business focused on hydrostatic testing. The purchase price was $10.4 million (net of cash acquired) and was financed through the Partnership's credit facilities. In addition, provisions in the purchase agreement provide for earn-out payments totaling up to $9.5 million dependent upon Brown's achieving certain financial milestones over a two-year period post-acquisition. Based on actual results since acquisition and forecasted results through the remainder of the earn-out period, we have not recorded a liability for the contingent consideration associated with this earn-out as it is currently considered remote that an earn-out will be earned and paid. The Partnership also has the right, but not the obligation, to acquire the remaining 49% of Brown commencing May 1, 2017 pursuant to a formula that would yield a maximum additional purchase price of $28.0 million in any combination of cash and Partnership units. The effective date of the transaction was May 1, 2015.

The acquisition of Brown qualified as a business combination and was accounted for under the acquisition method of accounting. We have recognized amounts for identified tangible and intangible assets acquired and liabilities assumed at their estimated acquisition date fair values based on discounted cash flow projections, estimated replacement cost and other valuation techniques. The Partnership used an estimate of replacement cost, based on comparable market prices, to value the acquired property and equipment and utilized discounted cash flows to value the intangible assets. Key assumptions used in the valuations included projections of future operating results and the Partnership's estimated weighted average cost of capital. Due to the unobservable nature of these inputs, these estimates are considered Level 3 fair value estimates.

The preliminary allocated purchase price and assessment of the fair value of the assets acquired and liabilities assumed as of the purchase date were as follows:

	(in thousands)
Cash	$ 175
Accounts receivable	3,229
Other current assets	108
Property and equipment	2,578
Intangible assets:	
Customer relationships	3,128
Trade names and trademarks	2,049
Non-competition agreements	143
Goodwill	9,992
	21,402
Current liabilites	1,294
Non-controlling interests	9,497
Net assets acquired	$ 10,611

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Intangible assets are amortized on a straight-line basis over periods ranging from 5 – 10 years. Goodwill represents the excess of the purchase price and the fair value of non-controlling interests over the fair value of identified tangible and intangible assets less the fair value of liabilities assumed. The Partnership believes that the locations, synergies created, and the projected future cash flows of Brown merit the recognition of this asset. The goodwill is fully deductible for income tax purposes by our partners.

The operating results of Brown are included in our Integrity Services segment which was created during the second quarter of 2015 in conjunction with the Brown acquisition (see Note 14).

Summarized as reported and pro forma information for the years ended December 31, 2015, 2014 and 2013 follows:

	Years ended December 31,		
	2015	**2014**	**2013**
	(in thousands)		
Revenues - as reported	$371,191	$404,418	$249,133
Revenues - pro forma	375,423	419,013	258,877
Net income (loss) - as reported	$4,091	$(15,179)	$4,355
Net income (loss) - pro forma	3,427	(13,984)	6,572

These pro forma results are for comparative purposes only and may not be indicative of the results that would have occurred had the acquisition happened as of the beginning of the periods presented or results that may be attained in the future.

TIR Entities

Effective February 1, 2015, the Partnership acquired the remaining 49.9% interest in the TIR Entities previously held by affiliates of Holdings for $52.6 million. We financed this acquisition with borrowings under our acquisition revolving credit facility (see Note 7). The amount paid in excess of the previously recorded non-controlling interest in the TIR Entities has been reflected in the Consolidated Statement of Owners' Equity as a distribution to the General Partner.

2014 Business Combination

SWD Acquisition

Effective December 1, 2014, we acquired a recently constructed commercial SWD facility from SBG Energy (a related party) for a total purchase price of approximately $1.7 million. The facility had minimal operating activity prior to the acquisition. The acquisition qualified as a business combination and was accounted for under the acquisition method of accounting. Accordingly, we recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values. The Partnership used various assumptions to determine fair value including, but not limited to, replacement costs, liquidation values and future cash flows on a discounted basis. The acquisition was funded with borrowings from our credit facility.

The fair value of the assets acquired and liabilities assumed as of the purchase date were as follows:

	(in thousands)
Current assets	$ 50
Property and equipment	1,837
Intangible assets:	
Contracts	241
	2,128
Current liabilites	386
Asset retirement obligation	1
Net assets acquired	$ 1,741

In addition to the amounts reflected above, the Partnership incurred additional capital costs of approximately $0.4 million to complete the SWD facility.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

2013 Business Combinations

TIR Entities Acquisition

As discussed in Note 2, Holdings acquired a controlling interest in the TIR Entities on June 26, 2013. This transaction qualified as a business combination and therefore, the assets and liabilities were recorded at their fair value under the acquisition method of accounting. Holdings used various assumptions to determine fair value including, but not limited to, replacement costs, liquidation values, future cash flows on a discounted basis, pay-off values and average industry royalty rates. Due to the unobservable nature of these assumptions, these fair value measurements are considered to be Level 3 fair value estimates.

The fair value of the assets and liabilities acquired as of June 26, 2013 were as follows:

	(in thousands)
Cash	$ 10,108
Other working capital, net	33,990
Property and equipment	1,075
Intangible assets:	
Customer relationships	21,380
Trade names and trademarks	10,850
Inspector database	2,080
Goodwill	40,638
	120,121
Mezzanine debt	19,756
Factoring debt	36,748
Net assets acquired	$ 63,617

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Notes to Consolidated Financial Statements - Continued

SBG Disposal Acquisition

Effective October 1, 2013, the Partnership acquired certain assets, including certain property and equipment, SWD facility management contracts, including contracts to provide services to the Partnership's SWD facilities, a 25% interest in a SWD facility and certain working capital from SBG Disposal LLC, a subsidiary of SBG Energy, in exchange for \$0.5 million from available cash on hand and a 49% ownership in CES LLC. In conjunction with a previous acquisition, the Partnership had assigned a fair value of \$0.2 million to an option to purchase these assets. The exercise of this option, along with the cash purchase price, totaled \$0.7 million. In addition, the 49% interest in CES LLC had a fair value of \$0.7 million resulting in total consideration of \$1.4 million.

The acquisition qualified as a business combination and was accounted for under the acquisition method of accounting. Accordingly, we recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values. The Partnership used a discounted cash flow model to value the customer relationships and the 25% interest in the SWD facilities and made market assumptions for the estimation of future water to be disposed of as discussed in Note 2. The Partnership also used an estimate of replacement cost to value the acquired property and equipment. Due to the unobservable nature of the inputs, these estimates of the fair value of the acquired wells were considered Level 3 fair value estimates.

The purchase price and assessment of the fair value of the assets acquired and liabilities assumed as of the purchase date for the SBG Disposal acquisition were as follows:

	(in thousands)
Current assets	$ 35
Property and equipment	300
Intangible assets:	
Customer relationships	150
Goodwill	971
	1,456
Current liabilities	35
Net assets acquired	$ 1,421

The customer relationships are amortized over a five year period.

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Notes to Consolidated Financial Statements - Continued

4. Property and Equipment

Property and equipment consist of the following, recorded at cost, as of December 31, 2015 and 2014:

Asset Category	Useful Lives (years)	December 31, 2015	December 31, 2014
		(in thousands)	
Land		$2,114	$2,049
Land improvements	15	848	1,143
Buildings and leasehold improvements	30 - 39	1,396	1,056
Facilities, wells and equipment	5 - 15	17,711	22,666
Computer and office equipment	3 - 9	1,213	816
Vehicles and other	3 - 5	424	148
		23,706	27,878
Less accumulated depreciation		(5,369)	(3,538)
Net property and equipment		$18,337	$24,340

Depreciation expense is computed using the straight-line method over the estimated useful lives of the assets. Depreciation expense was $3.1 million, $4.1 million and $4.1 million for the Partnership for the years ended December 31, 2015, 2014 and 2013, respectively, of which $0.6 million, $0.2 million and $0.1 million was included as a component of costs of services for the years ended December 31, 2015, 2014 and 2013, respectively. Additionally, as a result of our impairment analysis, we wrote down the value of certain property and equipment which resulted in a decrease in accumulated depreciation of $1.3 million, $4.3 million $0.6 million in 2015, 2014 and 2013, respectively.

During 2015, 2014 and 2013, the Partnership recognized impairments of property and equipment at a number of its SWD facilities. At each of these facilities, the Partnership has experienced revenue and volume decreases due to lower commodity pricing and increasing competition and has forecasted decreases in drilling activity affecting volumes and revenues over the remaining life of the underlying assets. Given these indicators of impairment, the Partnership compared its estimates of undiscounted future cash flows from the facilities to the carrying amounts of the long-lived assets of the facilities, and determined they were no longer recoverable and were impaired. The Partnership recognized impairments on the facilities totaling $6.6 million, $12.8 million and $3.4 million, included in the *impairments* caption on the Consolidated Statement of Operations for the years ended December 31, 2015, 2014 and 2013.

The following table summarizes the impaired property and equipment in our W&ES segment for the years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,		
Asset Category	**2015**	**2014**	**2013**
	(in thousands)		
Land	$587	$1,527	$126
Land improvements	385	2,034	900
Buildings and leasehold improvements	568	1,054	169
Facilities, wells and equipment	6,951	19,679	3,756
Computer and office equipment	4	5	-
Vehicles and other	5	10	-
	8,500	24,309	4,951
Accumulated depreciation	(1,268)	(4,296)	(401)
Net book value of impaired properties prior to impairment	7,232	20,013	4,550
Estimated fair market value of impaired properties as of date of impairment	587	7,241	1,124
Impairments	$6,645	$12,772	$3,426

Fair value was determined using expected future cash flows, which is a Level 3 input as defined in Accounting Standards Codification ("ASC") 820, *Fair Value Measurement*. The cash flows are those expected to be generated by the market participants, discounted at the Partnership's estimated cost of capital. Because of the uncertainties surrounding the SWD facilities and the market conditions, including the Partnership's ability to generate and maintain sufficient revenues to operate the facilities profitably, our estimate of expected future cash flows may change in the near term resulting in the need to further adjust our determinations of fair value.

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Notes to Consolidated Financial Statements - Continued

5. Goodwill

Goodwill represents the excess of cost over fair value of the assets and liabilities of businesses acquired. Changes in goodwill are as follows:

	PIS	**IS**	**W&ES**	**Total**
	(in thousands)			
Balance - December 31, 2013	$40,618	$-	$34,848	$75,466
Impairments	-	-	(19,773)	(19,773)
Foreign currency translation	(148)	-	-	(148)
Balance - December 31, 2014	40,470	-	15,075	55,545
Goodwill from business combination	-	9,992	-	9,992
Foreign currency translation	(264)	-	-	(264)
Balance - December 31, 2015	$40,206	$9,992	$15,075	$65,273

Goodwill is not amortized, but is subject to annual reviews on November 1 for impairment at a reporting unit level. The reporting unit or units used to evaluate and measure goodwill for impairment are determined primarily from the manner in which the business is managed or operated. A reporting unit is an operating segment or a component that is one level below an operating segment. In accordance with ASC 350 "*Intangibles — Goodwill and Other*", we have assessed the reporting unit definitions and determined that at December 31, 2015, PIS, IS and W&ES and at December 31, 2014, PIS and W&ES are the appropriate reporting units for testing goodwill impairment. The accounting estimate relative to assessing the impairment of goodwill is a critical accounting estimate for each of our reporting segments.

For our PIS and IS reporting units, we performed qualitative assessments to determine whether the fair values of the reporting units were more likely than not less than their carrying values. Our evaluations consisted of assessing various qualitative factors including current and projected future earnings, capitalization, current customer relationships and projects and the impact of lower crude oil prices on our earnings. The qualitative assessments on these reporting units indicated that there was no need to conduct further quantitative testing for goodwill impairment, nor did our analysis indicate the reporting units were at risk for potential goodwill impairment. Different judgments from those we used in our qualitative analyses could result in the requirement to perform quantitative goodwill impairment analyses.

For our W&ES segment, after giving consideration to certain qualitative factors including trends in the energy industry and recorded impairments of property and equipment, we elected to perform a quantitative goodwill impairment analysis. We computed the fair value of the reporting unit employing multiple valuation methodologies, including a market approach (market price multiples of comparable companies) and an income approach (discounted cash flow analysis). This approach is consistent with the requirement to utilize all appropriate valuation techniques as described in ASC 820-10-35-24 "*Fair Value Measurements and Disclosures*." Given recent declines in the price of crude oil and the related impact on the valuations of energy related companies, relevant market data was difficult to obtain and was of limited usefulness. Accordingly, we relied heavily on the use of the income approach for the valuation of the reporting unit.

The W&ES segment has experienced increased competition in the regions in which we operate which has resulted in declining volumes and increased pricing pressure. Steady and continued declines in oil prices have intensified competitive pressures and had a direct impact on our revenues. Many of our customers have announced significantly reduced drilling programs in the Bakken. The decline in drilling will directly impact the amount of flowback and produced water that we process and dispose. The energy downturn is also expected to continue to negatively impact our pricing as our customers look for ways to reduce costs. In addition, as we process lower water volumes, in particular flowback water volumes directly attributable to drilling, we will recover less skim oil.

Based on our quantitative analysis, we determined that goodwill for W&ES was not impaired as of our 2015 annual review date. Because additional SWD property and equipment were impaired in the fourth quarter due to continued declines in disposed volumes and depressed prices, we updated our W&ES valuation through December 31, 2015. Based on these 2015 analyses, we determined that the carrying value of the W&ES reporting unit was less than the estimated fair market value and therefore, there was no goodwill impairment adjustment for 2015. In 2014, we determined that the carrying value of the W&ES reporting unit exceeded the fair value of the reporting unit resulting in a goodwill impairment charge of $19.8 million. Additionally, further unfavorable changes in the future are reasonably possible, and therefore, it is possible that we may incur additional impairment charges in the near future.

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6. Intangible Assets

Intangible assets consist of the following at December 31, 2015 and 2014:

	Useful Lives (years)	**December 31, 2015**	**December 31, 2014**
		(in thousands)	
Customer relationships	5 - 20	$24,257	$21,510
Contracts	3	241	241
Non-compete agreements	3	143	60
Trademarks and trade names	10	12,067	10,135
Inspector database	10	2,080	2,080
		38,788	34,026
Less accumulated amortization		(6,302)	(3,781)
Net intangibles		$32,486	$30,245

Amortization expense for the years ended December 31, 2015, 2014 and 2013 was $2.8 million, $2.4 million and $1.3 million respectively.

Future amortization expense of our intangible assets is estimated to be as follows:

Year Ending December 31,	*(in thousands)*
2016	$ 2,914
2017	2,914
2018	2,828
2019	2,804
2020	2,783

Thereafter	18,243
	$ 32,486

During the year ended December 31, 2013, the Partnership determined that one of its trade names in PIS was impaired and recorded an impairment charge of $0.7 million.

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Notes to Consolidated Financial Statements - Continued

7. Credit Agreement

The Partnership is party to a credit agreement (as amended, the "Credit Agreement") that provides up to $200.0 million in borrowing capacity, subject to certain limitations. The Credit Agreement includes a working capital revolving credit facility ("WCRCF") which provides up to $75.0 million in borrowing capacity to fund working capital needs and an acquisition revolving credit facility ("ARCF") which provides up to $125.0 million in borrowing capacity to fund acquisitions and expansion projects. In addition, the Credit Agreement provides for an accordion feature that allows us to increase the availability under the facilities by an additional $125.0 million. The Credit Agreement matures December 24, 2018.

At December 31, 2015 and 2014, outstanding borrowings under the Credit Agreement totaled $140.9 million and $77.6 million, respectively. Borrowings under the WCRCF totaled $52.0 and $50.0 million at December 31, 2015 and 2014, respectively. Borrowings under the WCRCF are limited by a monthly borrowing base calculation as defined in the Credit Agreement. If, at any time, outstanding borrowings under the WCRCF exceed the Partnership's calculated borrowing base, principal in the amount of the excess is due upon submission of the borrowing base calculation. Borrowings under the ARCF totaled $88.9 million and $27.6 million at December 31, 2015 and 2014, respectively. Available borrowings under the ARCF may be limited by certain financial covenant ratios as defined in the agreement. The obligations under our Credit Agreement are secured by a first priority lien on substantially all assets of the Partnership.

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 1.25% to 2.75% per annum ("Base Rate Borrowing") or (ii) an adjusted LIBOR rate plus a margin of 2.25% to 3.75% 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 Credit Agreement borrowings ranged between 2.68% and 4.17% for the year ended December 31, 2015 and 2.65% and 3.50% for the year ended December 31, 2014. 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. Interest paid during the years ended December 31, 2015 and 2014 was $5.2 million and $3.1 million, respectively, including commitment fees.

Our Credit Agreement contains various customary affirmative and negative covenants and restrictive provisions. Our Credit Agreement also requires maintenance of certain financial covenants, including a combined total adjusted leverage ratio (as defined in our Credit Agreement) of not more than 4.0 to 1.0 and an interest coverage ratio (as defined in our Credit Agreement) of not less than 3.0 to 1.0. At December 31, 2015, our total adjusted leverage ratio was 3.07 to 1.0 and our interest coverage ratio was 4.84 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 our Credit Agreement, the lenders may declare any outstanding principal of our Credit Agreement debt, together with accrued and unpaid interest, to be immediately due and payable and may exercise the other remedies set forth or referred to in our Credit Agreement. We expect to remain in compliance with all of our financial debt covenants throughout the next twelve months.

In addition, our Credit Agreement restricts our ability to make distributions on, or redeem or repurchase, our equity interests. 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 our Credit Agreement, the borrowers and the guarantors are in compliance with the financial covenants, the borrowing base (which includes 100% of cash on hand) exceeds the amount of outstanding credit extensions under the WCRCF by at least $5.0 million and at least $5.0 million in lender commitments are available to be drawn under the WCRCF.

On May 4, 2015, the Partnership and the Partnership's lenders entered into Amendment No. 2 to the Credit Agreement ("Amendment"), which amended the Credit Agreement to, among other matters, (i) allow each of Tulsa Inspection Resources – Canada ULC and Foley Inspection Services ULC to join the Credit Agreement as an additional borrower under the Credit Agreement, and (ii) amend certain other provisions of the Credit Agreement as more specifically set forth in the Amendment.

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Notes to Consolidated Financial Statements - Continued

The following table reflects the changes in long-term debt during the year:

Long-term debt	**Working Capital Revolving Credit Facility**	**Acquisition Revolving Credit Facility**	**Total**
	(in thousands, except %'s)		
Balance - December 31, 2014	$50,000	$ 27,600	$77,600
Incremental borrowings:			
Acquisition of TIR Entities (remaining 49.9%)	-	52,600	52,600
Acquisition of 51% of Brown	2,000	8,700	10,700
Balance - December 31, 2015	$52,000	$ 88,900	$140,900
Weighted average interest rate at December 31, 2015	3.7 %	4.1 %	

8. Income Taxes

As a limited partnership, we generally are not subject to federal, state or local income taxes. The tax on the net income of the Partnership is generally borne by the individual partners. We have Canadian activity that remains taxable in Canada. In addition, we own three entities which have elected to be taxed as corporations for U.S. federal income tax purposes. The amounts recognized as income tax expense, income taxes payable, deferred tax assets and deferred tax liabilities on the Consolidated Financial Statements represent the Canadian and U.S. taxes referred to above, as well as partnership-level taxes levied by various states (primarily Texas).

From January 1, 2013 to December 9, 2013, Tulsa Inspection Resources, Inc. (“TIR Inc.”), the predecessor of the TIR Entities, operated as a taxable corporation. On December 9, 2013, TIR Inc. converted to a Limited Liability Company (“LLC”). The Partnership recognized a one-time tax provision of $15.0 million associated with the gain on the deemed sale of TIR Inc. associated with the conversion to a pass-through entity. To calculate the gain on conversion, the Partnership determined the fair value of the assets and liabilities as of the date of conversion. We used various assumptions to determine fair value including, but not limited to, estimating replacement costs, liquidation values, future cash flows on a discounted basis, pay-off values and average industry royalty rates. Due to the unobservable nature of the assumptions used in the valuation analysis, these fair value measurements are considered to be Level 3 fair value measurements. The resulting fair value of TIR Inc. was used as the hypothetical proceeds under the deemed sale at conversion and the tax provision was calculated on the resulting gain. The tax expense associated with the conversion of TIR Inc. on December 9, 2013 is included in *income tax expense* on the Consolidated Statement of Operations for the year ended December 31, 2013.

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Notes to Consolidated Financial Statements - Continued

Significant components of income tax expense (benefit) are as follows for the years ended December 31:

	2015	2014	2013
		(in thousands)	
Current tax expense (benefit)			
Federal	$(123)	$ 38	$14,714
State	501	332	2,462
Canadian	6	100	285
Total	384	470	17,461
Deferred tax expense (benefit)			
Federal	45	(12)	(1,553)
State	13	(3)	(390)
Canadian	10	13	(281)
Total	68	(2)	(2,224)
Total income tax expense	$452	$ 468	$15,237

Current deferred tax assets and liabilities of the Partnership mainly relate to Canadian net operating losses, offset by prepaid expenses. Non-current deferred tax assets and liabilities are primarily attributable to accumulated amortization of intangible assets. The Canadian net operating loss expires in 2026 and as such, the Partnership has made no valuation allowance against this deferred tax asset as of December 31, 2015 or 2014.

The following table reconciles the differences between the U.S. federal statutory rate of 35% to the Partnership's income tax expense on the Consolidated Statements of Operations for the years ended December 31:

	2015	2014	2013
		(in thousands)	
Tax (benefit) computed at statutory rate of 35%	$1,590	$ (5,149)	$6,857
(Income) loss not subject to federal taxes	(1,790)	5,274	(4,793)
State income taxes, net of federal benefit	514	326	535
Tax on conversion of TIR, Inc. to pass through entities	-	-	12,892
Other	138	17	(254)

Total income tax expense	$452	$ 468	$15,237

The Internal Revenue Service commenced an income tax audit of the 2012 Tulsa Inspection Resources, Inc. (the predecessor of the TIR Entities) federal income tax return beginning in January 2016. The Omnibus Agreement discussed in Note 12 provides that Holdings will indemnify us for certain liabilities associated with operations prior to the closing of the IPO should they arise in the course of this examination. As of this point in time, there have been no audit adjustments made to that corporate income tax return as filed. Tax years that remain subject to examination by various taxing authorities for each of our consolidated entities include the years 2012 through 2015.

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Notes to Consolidated Financial Statements - Continued

9. Parent Net Investment and Owners' Equity

Parent Net Investment

For the periods prior to the IPO, the net equity of the contributed entities is included in *parent net investment attributable to controlling interest* in the Consolidated Statement of Owners' Equity as of December 31, 2013. Also, prior to the IPO, CEP LLC provided treasury and accounts payable services for Holdings and other affiliates. Amounts paid on behalf of Holdings and its affiliates, net of cash transfers from Holdings, are included as a component of parent net equity. Cumulative advances for the periods prior to the IPO as of December 31, 2014 and 2013 were $0.2 million and $3.5 million, respectively.

Common Units and Subordinated Units

As of December 31, 2015, there are 5,920,467 common units and 5,913,000 subordinated units outstanding. Items of income / loss are allocated to common units and subordinated units equally. The common unitholders will have the right to receive the minimum quarterly cash distributions of $0.3875 per common unit, plus any arrearages in the payment of the minimum quarterly distributions on the common units from prior quarters, before any distributions of available cash may be made on the subordinated units. These units are deemed "subordinated" because, for the subordination period as defined in our offering documents, the subordinated units will not be entitled to receive any distributions until the common units have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. For the years ended December 31, 2015 and 2014, there were no limitations or arrearages related to the quarterly distributions made by the Partnership.

Incentive Distribution Rights

Our General Partner owns a 0.0% non-economic general partnership interest in the Partnership, which does not entitle it to receive cash distributions. Our General Partner holds incentive distribution rights ("IDRs"), which represent the right to receive an increasing percentage (15%, 25% and 50%) of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and target distribution levels have been achieved. The General Partner would begin receiving incentive distribution payments when the quarterly cash distribution exceeds

$0.445625 per unit. There were no incentive distribution payments in 2015 or 2014.

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Notes to Consolidated Financial Statements - Continued

10. Major Customers

For the year ended December 31, 2015 and 2014, three customers individually exceeded 10% of our consolidated total revenues: Enbridge Energy Partners, Enterprise Products Partners and Plains All America Pipeline. For the year ended December 31, 2013, Enbridge Energy Partners and Enterprise Products Partners each individually made up more than 10% of total consolidated revenues. No other customer accounted for more than 10% of our consolidated revenues during these years. Revenues from these customers resulted from inspection operations, which are activities conducted by our PIS segment.

11. Equity Compensation

Partnership Long-Term Incentive Plan ("LTIP")

Effective at the closing of the IPO, our General Partner adopted an LTIP that authorized up to 1,182,600 units, representing 10% of the initial outstanding units. Certain directors and employees of the Partnership have been awarded Phantom Restricted Units ("Units") under the terms of the LTIP. The fair value of the awards issued is determined based on the quoted market value of the publically traded common units at each grant date, adjusted for a forfeiture rate, and other discounts attributable to the awarded units. This valuation is considered a Level 3 measurement under the fair value measurement hierarchy. Compensation expense is recognized straight-line over the vesting period of the grant. Prior to 2015, Holdings reimbursed the Partnership for the direct expense of the awards and allocated the expense to us through the annual administrative fee provided for under the terms of our amended and restated omnibus agreement (see Note 12). For the years ended December 31, 2015 and 2014, compensation expense of $1.2 million and $0.5 million, respectively was recorded under the LTIP. The following table sets forth the grants and forfeitures of Units under the LTIP for the years ended December 31, 2015 and 2014:

	Number of Units	Weighted Average Grant Date Fair Value / Unit

Units at January 1, 2014	-	
Units granted	178,264	$ 17.96
Units forfeited	(19,911)	$ (16.78)
Units at December 31, 2014	158,353	$ 18.11
Units granted	230,310	$ 12.08
Units vested and issued	(7,467)	$ (19.72)
Units forfeited	(19,498)	$ (16.92)
Units at December 31, 2015	361,698	$ 14.30

Outstanding Units issued to directors vest ratably over a three year period from the date of grant. Units granted to employees vest over either five year, three year or eighteen month periods from the date of grant. For the five year awards, one third vests at the end of the third year, one third at the end of the fourth year and one third at the end of the fifth year. The eighteen month awards vest 100% at the end of the vesting period. Certain Units issued in the third quarter of 2015 vest 100% at the end of three years if certain performance measures are met as outlined in the performance award grant. Some of the awards vest in full upon the occurrence of certain events as defined in the LTIP agreement. Total unearned compensation associated with the LTIP at December 31, 2015 and 2014 was $3.4 million and $2.1 million, respectively, with an average remaining life of 3.3 years and 3.9 years, respectively.

In conjunction with the IPO, phantom profits interest units previously issued under a previous LTIP were exchanged for 44,250 Units under the Partnership's LTIP. Vesting under all of the exchanged awards was retroactive to the initial grant date. The awards are considered for all purposes to have been granted under the Partnership's LTIP. In addition, at IPO, certain profits interest units previously issued were converted into 44,451 subordinated units of the Partnership outside of the LTIP. Vesting for the subordinated units is retroactive to the initial grant date. Compensation expense associated with the subordinated units was $0.1 million and $0.3 million for the years ended December 31, 2015 and 2014, respectively. The exchange of the phantom profits interest units and the profits interest units resulted in the reversal of the existing equity compensation liability of $0.1 million in the first quarter of 2014 as the new awards were accounted for as equity. The unearned compensation related to the subordinated units was $0.3 million with an average remaining life of 2.1 years.

TIR Entities Stock Option Plan

On January 1, 2011, TIR Inc., executed a Stock Option Plan to allow certain share based compensation to be issued to employees, non-employee directors and contractors. Under the plan, TIR Inc. could award up to 14 shares of common stock from authorized unissued shares or shares held in treasury. At the discretion of the administrator of the Stock Option Plan, employees, non-employee directors and consultants may be granted awards in the form of incentive stock options, non-qualified stock options or restricted shares, any of which may be service, market or performance based awards. Total compensation expense recognized related to the non-qualified stock options issued was $0.2 million for the period from June 26, 2013 through December 31, 2013.

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Notes to Consolidated Financial Statements - Continued

During 2013, the TIR Entities' board authorized the vesting of certain management options. Management opted to execute the vested options using a cashless exercise, net of employee owed taxes, after which the issued shares were subsequently sold to Cypress Energy Partners – TIR, LLC ("CEP-TIR"). TIR Inc. paid the employee taxes owed of $0.6 million, recording the payment as a purchase of treasury shares. The shares were purchased from the employees at their estimated fair value, which was determined based on several factors including the average price of recent share transactions between affiliated and non-affiliated parties. Compensation expense was recognized for the excess of the fair value of the shares received over the price paid for the shares, totaling $1.75 million. The tax benefit associated with the employee compensation totaled $0.7 million, of which $0.2 million was included in the 2013 tax provision, offsetting the cumulative tax benefit from compensation expense previously recorded by TIR Inc. The remaining $0.5 million, representing the additional tax benefit in excess of the tax benefit from options previously expensed by TIR Inc., is included as a reduction of equity. Additionally, certain management options were forfeited as a result of the conversion of TIR Inc. to a pass-through entity on December 9, 2013.

Option activity and changes during 2013 were as follows:

	Quantity *(in shares)*	**Intrinsic Value** *(in thousands)*
Outstanding at June 26, 2013	7	$ 2,450
Exercised	(5)	(1,750)
Forfeited or expired	(2)	(700)
Outstanding at December 31, 2013	-	$ -

12. Related-Party Transactions

Omnibus Agreement

Effective as of the closing of the IPO, we entered into an omnibus agreement with Holdings and other related parties. The omnibus agreement, as amended in February 2015, governs the following matters, among other things:

- our payment of an annual administrative fee in the amount of $4.04 million and $4.0 million for the years ended December 31, 2015 and 2014, respectively, to be paid in quarterly installments (pro-rated in 2014 from the IPO date) to Holdings for providing certain partnership overhead services, including certain executive management services by certain officers of our General Partner, and payroll services for substantially all employees required to manage and operate our businesses. This fee also includes the incremental general and administrative expenses we incur as a result of being a publicly traded partnership;

- our right of first offer on Holdings' and its subsidiaries' assets used in, and entities primarily engaged in, providing SWD and other water and environmental services; and

- indemnification of us by Holdings for certain environmental and other liabilities (including income tax liabilities), including events and conditions associated with the operation of assets that occurred prior to the closing of the IPO and our obligation to indemnify Holdings for events and conditions associated with the operation of our assets that occur after the closing of the IPO and for environmental liabilities related to our assets to the extent Holdings is not required to indemnify us.

So long as Holdings controls our General Partner, the omnibus agreement will remain in full force and effect, unless we and Holdings agree to terminate it sooner. If Holdings ceases to control our General Partner, either party may terminate the omnibus agreement, provided that the indemnification obligations will remain in full force and effect in accordance with their terms. We and Holdings may agree to further amend the omnibus agreement; however, amendments that the General Partner determines are adverse to our unitholders will also require the approval of the Conflicts Committee of our Board of Directors.

The amount charged by Holdings under the omnibus agreement for the years ended December 31, 2015 and 2014 was $4.04 million and $3.8 million (2014 amount pro-rated from the IPO date) and is reflected in *general and administrative* in the Consolidated Statements of Operations. As of December 31, 2015, there was $1.0 million included in *accounts payable – affiliates* on the Consolidated Balance Sheets associated with the fourth quarter omnibus liability. The amount was paid to Holdings in March 2016. Additional expenses were incurred in the years ended December 31, 2015 and 2014 by Holdings in support of the Partnership totaling $0.6 million and $0.5 million, respectively. These expenses were also allocated to the Partnership and are reflected in *general and administration* in the Statements of Operations and as a *contribution attributable to General Partner* on the Consolidated Statement of Owners' Equity.

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Notes to Consolidated Financial Statements - Continued

Other Related Party Transactions

A current board member and business partner in North Dakota has an ownership interest in entities with which the Partnership transacts business including:

Creek Energy Services, LLC ("Creek," – formerly Rud Transportation, LLC) – Total revenue recognized by the Partnership from Creek was $1.1 million, $2.1 million and $1.8 million for the years ended December 31, 2015, 2014 and 2013, respectively. Accounts receivable from Creek was $0.1 million and $0.3 million at December 31, 2015 and 2014, respectively, and is included in *trade accounts receivable, net* in the Consolidated Balance Sheets.

SBG Pipeline SW 3903, LLC ("3903") – Total revenue recognized by the Partnership from 3903 was $0.6 million for the year ended December 31, 2015, prior to the sale of the ownership interest to an unrelated third party effective June 30, 2015. There were no revenues received from 3903 for the years ended December 31, 2014 and 2013.

Effective June 1, 2015, an affiliate of SBG Energy assigned and transferred its 49% membership interest in Cypress Energy Services, LLC ("CES LLC") to the Partnership for one dollar (the "CES Transaction"). As a result, the Partnership now owns 100% of CES LLC. Because we already controlled and consolidated CES LLC in our Consolidated Financial Statements, the previously recorded non-controlling interest in CES LLC has been reflected in the Consolidated Statement of Owners' Equity as an increase in equity of $0.9 million for our common and subordinated unitholders.

The CES Transaction was completed in conjunction with another transaction with SBG Energy effective July 1, 2015. On that date, the Partnership waived its rights to purchase and its rights of first refusal related to certain SWD assets pursuant to a previous option agreement with SBG Energy in exchange for $1.0 million. The $1.0 million payment has been reflected in *gain on waiver of right of purchase and other, net* on the Consolidated Statements of Operations for the year ended December 31, 2015.

SBG Disposal, LLC ("SBG Disposal") – Prior to the acquisition of certain assets and management fee contracts by CES LLC effective October 1, 2013, SBG Disposal provided staffing, management and back office services for a portion of the Partnership's SWD facilities. SBG Disposal is a wholly owned subsidiary of SBG Energy and provided services totaling $1.8 million for the year ended December 31, 2013. These costs are included in *costs of services* on the Consolidated Statements of Operations.

Effective October 1, 2013, the Partnership provides management services to a 25% owned investee company, Alati Arnegard, LLC (“Arnegard”). Management fee revenue earned from Arnegard totaled \$0.7 million, \$0.6 million and \$0.2 million for the years ended December 31, 2015, 2014 and 2013, respectively. Accounts receivable from Arnegard totaled \$0.1 million at December 31, 2015 and 2014 and is included in *trade accounts receivable, net* on the Consolidated Balance Sheets.

Effective October 1, 2013, the Partnership began outsourcing staffing and payroll services to an affiliated entity, Cypress Energy Management – Bakken Operations, LLC (“CEM-BO”). CEM-BO was owned 49% by SBG Energy. Effective June 1, 2015, Holdings acquired the 49% ownership interest of CEM-BO and now owns 100% of CEM-BO. Total employee related costs paid to CEM-BO prior to the acquisition of the 49% ownership interest on June 1, 2015 were \$1.2 million, \$3.0 million and \$0.8 million for the years ended December 31, 2015, 2014 and 2013, respectively. Included in *accounts payable* on the Consolidated Balance Sheets was \$0.2 million at December 31, 2014 related to this arrangement. There were no accounts payable due CEM-BO at December 31, 2015.

During 2013, PIS had business activity with Contract Pro, a non-affiliated Canadian company owned by two former Foley Inspection Services, ULC (“TIR-Foley”) employees. Contract Pro offers employment services to specific individuals that could not otherwise be employed or placed by TIR-Foley. TIR-Foley invoiced customers for the services of the Contract Pro employees and made the associated payments to Contract Pro, while keeping a portion of the proceeds. In addition, Contract Pro reimbursed TIR-Foley for certain services, as the company shared TIR-Foley offices for a portion of the 2013 calendar year. During 2013, Contract Pro separated their operations from TIR-Foley’s offices and the owners of Contract Pro resigned their employment positions with TIR-Foley. The payments, net of Contract Pro reimbursements, made by TIR-Foley and TIR-Canada to Contract Pro during 2013 totaled \$0.9 million.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

13. Commitments and Contingencies

Security Deposits

The Partnership has various performance obligations which are secured with short-term security deposits totaling $0.5 million at December 31, 2015 and 2014. These amounts are included in *prepaid expenses and other* on the Consolidated Balance Sheets.

Employment Contract Commitments

The Partnership has employment agreements with certain executives. The executive employment agreements are effective for a term of three-to-five years from the commencement date, after which time they will continue on an "at-will" basis. These agreements provide for minimum annual compensation, adjusted for annual increases as authorized by the Board of Directors. Certain agreements provide for severance payments in the event of specified termination of employment. At December 31, 2015 and December 31, 2014, the aggregate commitment for future compensation and severance was approximately $1.4 million and $0.9 million, respectively.

Compliance Audit Contingencies

Certain customer master service agreements ("MSA's") offer our customers the opportunity to perform periodic compliance audits, which include the examination of the accuracy of our invoices. Should our invoices be determined to be inconsistent with the MSA, or inaccurate, the MSA's may provide the customer the right to receive a credit or refund for any overcharges identified. At any given time, we may have multiple audits ongoing. Throughout 2015, several ongoing audits have concluded without adjustment to the books and records of the Partnership. At December 31, 2014, the Partnership had contingent liabilities of $0.1 million and $0.2 million, respectively, associated with the probable settlement of customer audits of various charges previously approved by customer representatives. The contingent liability is reflected in *accrued payroll and other* on the Consolidated Balance Sheets as of December 31, 2015 and 2014. In March 2016, the Partnership reached an agreement to settle an outstanding customer audit for $0.1 million.

Management Service Contracts

The Partnership has historically provided management services for non-owned SWD facilities under contractual arrangements. Principals of two of these management services contract customers (under common control) approached the Partnership about selling their interest in the managed SWD facilities to the Partnership. Due to a number of factors, including the depressed energy economy and the proposed asking price for these facilities, the Partnership was unwilling to enter into a purchase agreement for the facilities. Subsequently, in May 2015, the Partnership was notified by these principals that they were terminating the management contracts related to these two facilities. While management of the Partnership believes that the parties do not have the right to terminate the agreements pursuant to the terms of the agreements, the termination of these agreements has resulted in a reduction of management fee revenue and corresponding labor costs associated with staffing the facilities. Management fee revenues related to these contracts totaled $0.3 million and $1.5 million for the years ended December 31, 2015 and 2014, respectively, prior to the customer's improper termination of the agreements. After settlement discussions failed, the Partnership commenced litigation proceedings regarding the improper termination of these agreements. (See *Legal Proceedings*.)

Legal Proceedings

On July 3, 2014, a group of former minority shareholders of Tulsa Inspection Resources, Inc. ("TIR Inc.", the predecessor of the TIR Entities), formerly an Oklahoma corporation, filed a civil action in the United States District Court for the Northern District of Oklahoma against TIR LLC, members of TIR LLC, and certain affiliates of TIR LLC's members. TIR LLC is the successor in interest to TIR Inc., resulting from a merger between the entities that closed in December 2013 (the "TIR Merger"). The former shareholders of TIR Inc. claim that they did not receive sufficient value for their shares in the TIR Merger and are seeking rescission of the TIR Merger or, alternatively, compensatory and punitive damages. The Partnership is not named as a defendant in this civil action. TIR LLC and the other defendants have been advised by counsel that the action lacks merit. We believe that the possibility of the Partnership incurring material losses as a result of this action is remote. In addition, the Partnership anticipates no disruption in its business operations related to this action.

In September 2015, Flatland Resources I, LLC and Flatland Resources II, LLC, two of our management services customers (under common ownership) initiated a civil action in the District Court for the McKenzie County District of the State of North Dakota against CES LLC. The customers claim that CES LLC breached the management agreements and interfered with their business relationships, and seek to rescind the management agreements and recover any damages. The customers initiated this lawsuit upon dismissal from federal court due to lack of jurisdiction of CES LLC's lawsuit against the customers seeking to enforce the management agreements. CES LLC subsequently filed an answer and counterclaims, as well as a third party complaint against the principal of the customers seeking to enforce the management agreements and other injunctive relief, as well as monetary damages. The court subsequently granted CES's motion to transfer venue to the Grand Forks County District Court. We believe that the possibility of the Partnership incurring material losses as a result of this action is remote.

Internal Revenue Service Audits

In January 2016, the Partnership received notices from the Internal Revenue Service ("IRS") that conveyed its intent to audit the consolidated income tax return of TIR, Inc. for the 2012 tax year and audit payroll and payroll tax filings of TIR Inc. for the 2013 tax year. Currently, the IRS is in the process of acquiring information in order to perform and complete their audit procedures. Based on the terms of the Partnership's omnibus agreement with Holdings, Holdings would indemnify the Partnership for certain liabilities (including income tax liabilities) associated with the operation of assets that occurred prior to the closing of our IPO should any liabilities arise as a result of these audits. Because of this, the Partnership believes that the possibility of incurring material losses as a result of these IRS audits is remote.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Leases

The Partnership has entered into land lease agreements on four of its SWD facilities. The leases generally provide for initial terms of 15 – 20 years with renewal options. The Partnership also maintains various office leases in the U.S. and Canada, with its corporate offices in Tulsa, OK. Lease expense under these operating leases was $0.8 million for the year ended December 31, 2015 and $0.1 million for the years ended December 31, 2014 and 2013.

Minimum annual lease commitments under the current office lease and other operating leases at December 31, 2015 follows:

	(in thousands)
2016	$ 748
2017	674
2018	132
2019	52
2020	25
Thereafter	530
Total	$ 2,161

14. Segment Disclosures

The Partnership's operations consist of three reportable segments: (i) Pipeline Inspection Services ("PIS"), (ii) Integrity Services ("IS") and (iii) Water and Environmental Services ("W&ES"). In conjunction with the Brown acquisition (Note 3) in the second quarter of 2015, we created the IS segment. The economic characteristics of Brown were sufficiently dissimilar from our existing Pipeline Inspection and Integrity Services segment resulting in the creation of a new segment. As a result, the Pipeline Inspection and Integrity Services segment was renamed Pipeline Inspection Services.

PIS – This segment represents our pipeline inspection services operations. We aggregate these operating entities for reporting purposes as they have similar economic characteristics, including centralized management and processing. This segment provides independent inspection and integrity services to various energy, public utility and pipeline companies. The inspectors in this segment perform a variety of 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 and type of inspectors performing services for customers and the fees charged for those services, which depend on the nature and duration of the project.

IS – This segment includes the acquired operations of Brown (Note 3). This segment provides independent hydro-testing integrity services to major natural gas and petroleum pipeline companies, as well as pipeline construction companies located throughout the United States. Field personnel in this segment primarily perform hydrostatic testing on newly constructed and existing natural gas and petroleum pipelines. Results in this segment are driven primarily by field personnel performing services for customers and the fees charged for those services, which depend on the nature, scope and duration of the project.

W&ES – This segment includes the operations of ten SWD facilities, fees related to the management of third party SWD facilities, as well as an equity ownership in one managed facility. We aggregate these operating entities for reporting purposes as they have similar economic characteristics and have centralized management and processing. Segment results are driven primarily by the volumes of produced water and flowback water we inject into our SWD facilities and the fees we charge for our services. These fees are charged on a per barrel basis and vary based on the quantity and type of saltwater disposed, competitive dynamics and operating costs. In addition, for minimal marginal cost, we generate revenue by selling residual oil we recover from the disposed water.

Other – These amounts represent corporate and overhead items not specifically allocable to the other reportable segments.

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CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

The following table outlines segment operating income and a reconciliation of total segment operating income to net income before income tax expense.

	PIS	IS	W&ES	Other	Total
	(in thousands)				
Twelve months ended December 31, 2015					
Revenue	$341,929	$14,614	$14,648	$-	$371,191
Costs of services	309,584	10,398	6,279	-	326,261
Gross margin	32,345	4,216	8,369	-	44,930
General and administrative	16,672	2,490	3,351	1,282	23,795
Depreciation, amortization and accretion	2,512	421	2,494	-	5,427
Impairments	-	-	6,645	-	6,645
Operating income (loss)	$13,161	$1,305	$(4,121)	$(1,282)	9,063
Interest expense, net					5,656
Gain on waiver of right of purchase and other, net					(1,136)
Net income before income tax expense					$4,543
Twelve months ended December 31, 2014					
Revenue	$382,002	$-	$22,416	$-	$404,418
Costs of services	346,738	-	8,617	-	355,355
Gross margin	35,264	-	13,799	-	49,063
General and administrative	17,734	-	3,090	497	21,321
Depreciation, amortization and accretion	2,539	-	3,806	-	6,345
Impairments	-	-	32,546	-	32,546
Operating income (loss)	$14,991	$-	$(25,643)	$(497)	(11,149)
Interest expense, net					3,208
Offering costs					446
Other, net					(92)
Net loss before income tax expense					$(14,711)
Twelve months ended December 31, 2013					
Revenue	$226,901	$-	$22,232	$-	$249,133
Costs of services	206,343	-	7,347	-	213,690

Gross margin	20,558	-	14,885	-	35,443
General and administrative	9,175	-	3,292	-	12,467
Depreciation, amortization and accretion	1,327	-	3,837	-	5,164
Impairments	702	-	3,429	-	4,131
Operating income	$9,354	$-	$4,327	$-	13,681
Interest expense, net					4,000
Offering costs					1,376
Gain on reversal of contingent consideration					(11,250)
Other, net					(37)
Net income before income tax expense					$19,592

Total Assets

December 31, 2015	$130,657	$23,097	$38,418	$515	$192,687
December 31, 2014	$136,224	$-	$50,296	$3,322	$189,842

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CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements – Continued

15. Distributions

Our partnership agreement calls for minimum quarterly cash distributions. The following table summarizes the cash distributions declared and paid by the Partnership since our IPO. There were no cash distributions declared or paid prior to these distributions.

Payment Date	Per Unit Cash Distributions	Total Cash Distributions	Total Cash Distributions to Affiliates (a)
		(in thousands)	
May 15, 2014 (b)	$ 0.301389	$3,565	$ 2,264
August 14, 2014	0.396844	4,693	2,980
November 14, 2014	0.406413	4,806	3,052
Total 2014 Distributions	1.104646	13,064	8,296
February 14, 2015	0.406413	4,806	3,052
May 14, 2015	0.406413	4,808	3,053
August 14, 2015	0.406413	4,809	3,087
November 13, 2015	0.406413	4,809	3,092
Total 2015 Distributions	1.625652	19,232	12,284
February 12, 2016 (c)	0.406413	4,809	3,107
Total Distributions (through February 12, 2016 since IPO)	$ 3.136711	$37,105	$ 23,687

(a) Approximately 64.6% of the Partnership's outstanding units at December 31, 2015 are held by affiliates.
(b) Distribution was pro-rated from the date of our IPO through March 31, 2014.
(c) Fourth quarter 2015 distribution was declared and paid in 2016.

16. Condensed Consolidating Financial Information

The following financial information reflects consolidating financial information of the Partnership and its wholly owned guarantor subsidiaries and non-guarantor subsidiaries for the periods indicated. The information is presented in accordance with the requirements of Rule 3-10 under the SEC’s Regulation S-X. The financial information may not necessarily be indicative of financial position, results of operations or cash flows had the guarantor subsidiaries or non-guarantor subsidiaries operated as independent entities. The Partnership has not presented separate financial and narrative information for each of the guarantor subsidiaries or non-guarantor subsidiaries because it believes such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the guarantor subsidiaries and non-guarantor subsidiaries. The Partnership anticipates issuing debt securities that will be fully and unconditionally guaranteed by the guarantor subsidiaries. These debt securities will be jointly and severally guaranteed by the guarantor subsidiaries. There are no restrictions on the Partnership’s ability to obtain cash dividends or other distributions of funds from the guarantor subsidiaries.

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Condensed Consolidating Balance Sheets

As of December 31, 2015

(in thousands)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$378	$ 19,570	$ 4,202	$ -	$ 24,150
Trade accounts receivable, net	-	40,029	8,289	(53)	48,265
Receivables from affiliates	-	5,601	-	(5,601)	-
Deferred tax assets	-	-	34	-	34
Prepaid expenses and other	-	2,078	286	(35)	2,329
Total current assets	378	67,278	12,811	(5,689)	74,778
Property and equipment:					
Property and equipment, at cost	-	20,790	2,916	-	23,706
Less: Accumulated depreciation	-	4,941	428	-	5,369
Total property and equipment, net	-	15,849	2,488	-	18,337
Intangible assets, net	-	26,135	6,351	-	32,486
Goodwill	-	53,914	11,359	-	65,273
Investment in subsidiaries	43,021	10,465	-	(53,486)	-
Notes receivable - affiliates	-	14,514	-	(14,514)	-
Debt issuance costs, net	1,771	-	-	-	1,771
Other assets	-	32	10	-	42
Total assets	$45,170	$ 188,187	$ 33,019	$ (73,689)	$ 192,687
LIABILITIES AND OWNERS' EQUITY					
Current liabilities:					
Accounts payable	$6	$ 467	$ 1,732	$ -	$ 2,205
Accounts payable - affiliates	1,237	912	4,042	(5,278)	913
Accrued payroll and other	-	6,855	293	(53)	7,095
Deferred tax liabilities	-	42	-	-	42
Income taxes payable	-	385	-	(35)	350
Total current liabilities	1,243	8,661	6,067	(5,366)	10,605
Long-term debt	-	135,400	5,500	-	140,900
Notes payable - affiliates	-	-	13,850	(13,850)	-
Deferred tax liabilities	-	1	362	-	363
Asset retirement obligations	-	117	-	-	117
Total liabilities	1,243	144,179	25,779	(19,216)	151,985

Commitments and contingencies

Owners' equity:					
Total partners' capital	33,954	34,035	7,240	(44,500)	30,729
Non-controlling interests	9,973	9,973	-	(9,973)	9,973
Total owners' equity	43,927	44,008	7,240	(54,473)	40,702
Total liabilities and owners' equity	$45,170	$ 188,187	$ 33,019	$ (73,689)	$ 192,687

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Condensed Consolidating Balance Sheets

As of December 31, 2014

(in thousands)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$982	$ 16,598	$ 3,177	$ -	$ 20,757
Trade accounts receivable, net	-	49,569	4,514	(8)	54,075
Receivables from affiliates	22	8,809	-	(8,831)	-
Deferred tax assets	-	15	53	-	68
Prepaid expenses and other	-	2,339	101	-	2,440
Total current assets	1,004	77,330	7,845	(8,839)	77,340
Property and equipment:					
Property and equipment, at cost	-	27,769	109	-	27,878
Less: Accumulated depreciation	-	3,485	53	-	3,538
Total property and equipment, net	-	24,284	56	-	24,340
Intangible assets, net	-	28,414	1,831	-	30,245
Goodwill	-	53,915	1,630	-	55,545
Investment in subsidiaries	98,965	-	-	(98,965)	-
Notes receivable - affiliates	-	3,903	-	(3,903)	-
Debt issuance costs, net	2,318	-	-	-	2,318
Other assets	-	35	19	-	54
Total assets	$102,287	$ 187,881	$ 11,381	$ (111,707)	$ 189,842
LIABILITIES AND OWNERS' EQUITY					
Current liabilities:					
Accounts payable	$34	$ 2,161	$ 266	$ -	$ 2,461
Accounts payable - affiliates	-	586	8,839	(8,839)	586
Accrued payroll and other	6	7,605	139	-	7,750
Income taxes payable	-	507	39	-	546
Total current liabilities	40	10,859	9,283	(8,839)	11,343
Long-term debt	-	77,600	-	-	77,600
Notes payable - affiliates	-	-	3,479	(3,479)	-
Deferred tax liabilities	-	-	438	-	438
Asset retirement obligations	-	33	-	-	33
Total liabilities	40	88,492	13,200	(12,318)	89,414

Commitments and contingencies

Owners' equity:

Total partners' capital	75,764	98,380	(1,819)	(98,470)	73,855
Non-controlling interests	26,483	1,009	-	(919)	26,573
Total owners' equity	102,247	99,389	(1,819)	(99,389)	100,428
Total liabilities and owners' equity	$ 102,287	$ 187,881	$ 11,381	$ (111,707)	$ 189,842

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Condensed Consolidating Statements of Income

For the Year Ended December 31, 2015

(in thousands)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Revenues	$-	$ 329,086	$ 54,708	$ (12,603)	$ 371,191
Costs of services	-	290,524	48,340	(12,603)	326,261
Gross margin	-	38,562	6,368	-	44,930
Operating costs and expense:					
General and administrative	1,282	18,180	4,333	-	23,795
Depreciation, amortization and accretion	-	4,832	595	-	5,427
Impairments	-	6,645	-	-	6,645
Operating income (loss)	(1,282)	8,905	1,440	-	9,063
Other income (expense):					
Equity earnings in subsidiaries	6,115	1,010	-	(7,125)	-
Interest expense, net	(902)	(4,115)	(639)	-	(5,656)
Gain on waiver of right of purchase and other, net	-	1,116	20	-	1,136
Net income before income tax expense	3,931	6,916	821	(7,125)	4,543
Income tax expense	-	372	80	-	452
Net income	3,931	6,544	741	(7,125)	4,091
Net income attributable to non-controlling interests	143	429	-	27	599
Net income attributable to partners	$3,788	$ 6,115	$ 741	$ (7,152)	$ 3,492

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Condensed Consolidating Statements of Income

For the Year Ended December 31, 2014

(in thousands)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Revenues	$-	$ 370,081	$ 34,337	$ -	$ 404,418
Costs of services	-	323,821	31,534	-	355,355
Gross margin	-	46,260	2,803	-	49,063
Operating costs and expense:					
General and administrative	-	19,257	2,064	-	21,321
Depreciation, amortization and accretion	-	6,136	209	-	6,345
Impairments	-	32,546	-	-	32,546
Operating income (loss)	-	(11,679)	530	-	(11,149)
Other income (expense):					
Equity earnings in subsidiaries	(14,134)	-	-	14,134	-
Interest expense, net	(983)	(1,892)	(333)	-	(3,208)
Offering costs	(446)	-	-	-	(446)
Other, net	-	84	8	-	92
Net income (loss) before income tax expense	(15,563)	(13,487)	205	14,134	(14,711)
Income tax expense	-	356	112	-	468
Net income (loss)	(15,563)	(13,843)	93	14,134	(15,179)
Net income attributable to non-controlling interests	4,646	291	-	36	4,973
Net income (loss) attributable to partners	$(20,209)	$ (14,134)	$ 93	$ 14,098	$ (20,152)

Condensed Consolidating Statements of Income

For the Year Ended December 31, 2013

Non-Guarantors for the Period June 26, 2013 through December 31, 2013

(in thousands)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Revenues	$-	$ 222,250	$ 26,883	$ -	$ 249,133
Costs of services	-	188,928	24,762	-	213,690
Gross margin	-	33,322	2,121	-	35,443
Operating costs and expense:					
General and administrative	-	11,283	1,184	-	12,467
Depreciation, amortization and accretion	-	5,027	137	-	5,164
Impairments	-	3,429	702	-	4,131
Operating income (loss)	-	13,583	98	-	13,681
Other income (expense):					
Interest expense, net	(18)	(3,822)	(160)	-	(4,000)
Offering costs	(1,376)	-	-	-	(1,376)
Gain on reversal of contingent consideration	-	11,250	-	-	11,250
Other, net	-	41	(4)	-	37
Net income (loss) before income tax expense	(1,394)	21,052	(66)	-	19,592
Income tax expense	-	14,187	1,050	-	15,237
Net income (loss)	(1,394)	6,865	(1,116)	-	4,355
Net income attributable to non-controlling interests	-	22	-	-	22
Net income (loss) attributable to partners	$(1,394)	$ 6,843	$ (1,116)	$ -	$ 4,333

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Condensed Consolidating Statements of Comprehensive Income (Loss)

For the Year Ended December 31, 2015

(in thousands)

	Parent	**Guarantors**	**Non-Guarantors**	**Eliminations**	**Consolidated**
Net income	$3,931	$ 6,544	$ 741	$ (7,125)	$ 4,091
Other comprehensive loss-			-		
Foreign currency translation	-	-	(1,178)	(564)	(1,742)