Cypress Energy Partners, L.P.
Form 10-K
March 30, 2015

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

Form 10-K

(MARK ONE)

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

For the fiscal year ended December 31, 2014

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

FOR THE TRANSITION PERIOD FROM________ TO_______

Commission File No. 001-36260

CYPRESS ENERGY PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

Delaware	61-1721523
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

5727 South Lewis Avenue, Suite 500	
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: N o n e

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

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 ý 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, 2014 was $102,594,375.

As of March 25, 2015, the registrant had 5,913,000 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:

"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 11.4% of our outstanding common units and 4,939,299 subordinated units representing 83.5% of our subordinated units;

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

"CEM-BO" refers to Cypress Energy Management – Bakken Operations, LLC, a 51% owned subsidiary of CEM LLC;

"CEM TIR" refers to Cypress Energy Management - TIR, LLC, a wholly owned subsidiary of the General Partner;

"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, our 51.0% indirectly owned subsidiary that performs management services for 10 salt water disposal ("SWD") facilities in North Dakota – seven of which are owned by CEP LLC. SBG Energy Services, LLC ("SBG Energy") owns the remaining interests and CEP LLC has the right to acquire such interests;

"CF Inspection" refers to CF Inspection Management, LLC, owned 49% by TIR-PUC, controlled and consolidated by TIR-PUC;

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

·"PI&IS" refers to our Pipeline Inspection and Integrity Services business segment;

"Predecessor" refers to the accounting predecessor of CEP LLC, which is comprised of the seven North Dakota limited liability companies we acquired from SBG Energy Services, 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 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 own 100%;

“TIR-Foley” refers to Foley Inspection Services ULC, a Canadian subsidiary of TIR Holdings;

“TIR Holdings” refers to Tulsa Inspection Resources Holdings, LLC;

“TIR-NDE” refers to Tulsa Inspection Resources – Nondestructive Examination, LLC;

“TIR-PUC” refers to Tulsa Inspection Resources – PUC, LLC, a corporate subsidiary of TIR LLC; and

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

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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 phras 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 recently 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 two reportable segments: (1) Water and Environmental Services (“W&ES”) and (2) Pipeline Inspection and Integrity Services (“PI&IS”). 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. 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 51% subsidiary, CES LLC, provides management and staffing services for three additional SWD facilities in the Bakken Shale region, pursuant to management agreements. CES LLC also owns a 25% member interest in one of the managed wells. 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.

PI&IS is comprised of the operations of the TIR Entities. Through this segment, we provide independent inspection and integrity 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 and integrity 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.

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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 and Chief Executive Officer, 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 58.8% 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.

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 this 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.

PI&IS. We intend to continue to position ourselves as a trusted provider of high quality inspection and integrity services, as we believe the pipeline inspection and integrity 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 some of 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.

Optimize existing SWD assets. The average age of our SWD facilities was 2.3 years at the end of 2014. We estimate that we utilized approximately 45% of the aggregate estimated capacity of these facilities for the year ended December 31, 2014. 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 current downturn in the energy industry will place pressure on both the volumes we process and the prices we are able to charge.

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 2014 pipeline water volumes increased 68% from 2013. As a percentage of total water volume, pipeline water was 10% in 2013 and was 17% of total water volume in 2014. We will continue to focus on these pipeline opportunities.

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Leverage customer relationships in both of 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 two 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 PI&IS. In addition, we intend to enhance our relationships with our customers in PI&IS by broadening the services we provide, including expanding our ultrasonic nondestructive examination services and potentially offering hydro testing and nitrogen 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 both W&ES and PI&IS. Both of our business segments operate in industries that are fragmented, giving us the opportunity to make strategic and accretive acquisitions. We exercised important discipline in 2014 and avoided overpaying for acquisitions. We remain optimistic that some good opportunities will present themselves in the 2nd half of 2015. 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, like our December 2014 SWD facility acquisition. In addition, provided certain opportunities fit with our strategic plan of expanding our business, we intend to grow PI&IS by acquiring other strategic pipeline service companies that will allow us to broaden the suite of services we offer our existing customers. In addition, we expanded our PI&IS 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 operated in two segments: (1) Water and Environmental Services ("W&ES") and (2) Pipeline Inspection and Integrity Services ("PI&IS"). 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 build out of our segments.

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 three other SWD facilities that we also built for third parties in the Bakken Shale region through CES LLC, one of which is 25% owned. 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 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.

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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 well.

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 a 51.0% interest in CES LLC, a management and development company that manages three additional SWD facilities 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 these facilities generally based on the gross revenue of the facilities.

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, 2014 and 2013, produced water represented approximately 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. In the future, we anticipate that some 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.

The amount of saltwater disposed in our SWD facilities 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 compete for business with our locations.

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As of December 31, 2014, 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 51.0% of CES, a management and development company that owns a 25.0% non-controlling interest in this SWD facility.
(3) Certain SWD facilities are constructed on land leased under long term arrangements.

In addition to the above properties, we also manage two other SWD facilities in the Bakken Shale region.

PI&IS

Overview. We believe that PI&IS is a leading provider of independent inspection and integrity 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 and integrity services 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 year ended December 31, 2014 and for the period from June 26, 2013 through December 31, 2013, our Canadian operations generated \$0.6 and \$0.1 million, respectively, of the operating income attributable to PI&IS, representing less than 5% of the total PI&IS operating income in both years.

PI&IS 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 year ended December 31, 2014 and the period from June 26, 2013 through December 31, 2013, we employed or engaged an average of 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.

Principal Customers

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, 2014 and 2013, we had approximately 206 and 228 customers, respectively, in W&ES. Our ten largest customers generated approximately 60%, 55% and 73% of W&ES revenue for the years ended December 31, 2014, 2013 and 2012, respectively. For the year ended December 31, 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. Two customers each accounted for more than 10% of the segment revenues for the year ended December 31, 2012.

PI&IS

Customers of PI&IS 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, 2014 and

2013, PI&IS had approximately 85 customers. The five largest customers in this segment generated approximately 65% and 71% of our segment revenue for the year ended December 31, 2014 and for the period from June 26, 2013 through December 31, 2013, respectively. For the year ended December 31, 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 and integrity services customers accounted for more than 10% of our segment revenue.

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Competition

W&ES

The oilfield waste treatment, water and environmental services, and disposal business is highly competitive with relatively low barriers to entry. During the last year, competitors opened a number of new locations around our existing facilities based upon anticipated new drilling activity prior to the downturn 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.

PI&IS

The pipeline inspection and integrity business is highly competitive. PI&IS' 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.

Seasonality

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, this last 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.

PI&IS

Inspection and integrity 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.

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 believe that we are in compliance with current applicable environmental and occupational health and safety laws and regulations. However, these rules and regulations are constantly evolving at the federal, state, and local level. Further, 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. 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 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.

We are required to obtain permits for the disposal of E&P waste as part of our operations. The construction, operation and disposal operations are generally regulated at the state level. 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. We believe that we have obtained the necessary permits from these agencies for our underground injection wells and that we are in compliance with permit conditions and state rules and regulations. Although we monitor the injection process of our wells, any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in suspension of our UIC permit, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource and imposition of liability by third-parties 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 waters of the U.S. 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 waters of the U.S. occurred at one of our facilities, we could be liable for cleanup costs and damages under the OPA.

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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 state waters as well as waters of the U.S. and impose requirements affecting our ability to conduct activities in waters and wetlands. Pursuant to the Clean Water Act and analogous state laws, permits must be obtained to discharge pollutants into state waters or waters of the U.S., 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. We believe we are in compliance with the ESA and similar statutes. However, the designation of previously unidentified endangered or threatened species could indirectly cause us to incur additional costs or cause our or our customers' operations to become subject to operating restrictions or bans or limit future development activity in affected areas.

For example, the federal government is considering listing the greater sage-grouse as an endangered species whose natural habitats coincide with some of our areas of operation and the areas of operation of some of our customers. The lesser prairie-chicken was listed as threatened in March 2014. As part of conservation efforts to preserve that species, a coalition of state governments, NGOs and industry developed the Lesser Prairie-Chicken Range-Wide Conservation Plan. 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.

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, including the curtailment of new drilling or a refusal to allow a new pipeline to be constructed.

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

Our 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 approved 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. EPA's rule package requires new standards on all hydraulically-fractured wells constructed or re-fractured after January 1, 2015. 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.

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Climate change. In response to certain scientific studies suggesting that emissions of greenhouse gases, or GHGs, including carbon dioxide and methane, are contributing to the warming of the Earth's atmosphere and other climatic conditions, the U.S. Congress has 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. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of such allowances is expected to escalate significantly.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane, and other GHGs, present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. These findings served as a statutory prerequisite for EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the Clean Air Act. EPA has adopted two sets of related rules, one of which regulates emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. The EPA finalized the motor vehicle rule in April 2010 and it became effective January 2011. The EPA adopted the stationary source rule, also known as the "Tailoring Rule," in May 2010, and it also became effective January 2011. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including NGLs fractionators and local natural gas / distribution companies, beginning in 2011, for emissions occurring in 2010. More recently, in November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011. Additionally, in September 2013, the EPA published New Source Performance Standards for Greenhouse Gas emissions from Electric Utility Generating Units and a proposed rule in June 2014 limiting GHG emissions from existing coal-fired power plants. As a result of this continued regulatory focus, future GHG regulations of the oil and natural gas industry remain a possibility.

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. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies or the alleged link between the fluid injection associated with hydraulic fracturing and seismic activity, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing. The SDWA regulates the underground injection of substances through the UIC program and 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. The U.S. Congress may consider similar SDWA legislation in the future.

In addition, EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels in those states where EPA is the permitting authority. Also, in November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. Further, On October 21, 2011, the EPA announced its intention to propose federal Clean Water Act regulations in 2014 governing wastewater discharges from hydraulic fracturing and certain other natural gas operations. In addition, the U.S. Department of the Interior ("DOI") published a revised proposed rule on May 16, 2013 that would update existing regulation of hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water. DOI is expected to issue the final rule in 2015.

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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.

The EPA is conducting a study of the potential impacts of hydraulic fracturing activities on drinking water. The EPA issued a Progress Report in December 2012, and a final draft is yet to be published for peer review and public comment. 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. Some individuals and companies have linked seismic activity with both hydraulic fracturing and SWD facilities. In Oklahoma, a substantial number of seismic events have been blamed on saltwater disposal and SWD facilities. We do not currently operate any SWD facilities in Oklahoma. The Oklahoma Corporation Commission has been investigating and evaluating any potential impact SWD facilities may have on seismic activity. We believe that it is prudent to avoid building SWD facilities near known fault lines that may become lubricated with substantial volumes of saltwater. Some industry experts believe this lubrication helps avoid major seismic activity that would likely otherwise occur.

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, 2014 and 2013, that entity employed 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, PI&IS does not have any employees. All of the employees that conduct the PI&IS business do it through CEM TIR, providing the necessary personnel resources to PI&IS. PI&IS employed or engaged 1,147 and 1,476 inspectors as of December 31, 2014 and 2013, respectively, of which 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 PI&IS group vary month to month and project to project. The Tulsa headquarters group of PI&IS consists of approximately 70 employees who are 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.

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. CEM LLC also owns a 51% interest in CEM-BO, which provides staff for our North Dakota SWD facility operations. As of December 31, 2014 and 2013, CEM-BO employed approximately 39 and 41 employees, respectively. We pay CEM LLC and CEM-BO 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.

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 PI&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 25, 2015. 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 W&ES, as well as PI&IS;

- the volume of saltwater we handle in W&ES and the number and types of projects conducted by PI&IS;
- 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 acquisitions of other SWD facilities and pipeline inspection companies;
- the level of competition from other companies;
- governmental regulations, including changes in governmental regulations, in our industry;

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- prevailing economic and market conditions; and

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

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

- 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 years ended December 31, 2012 or 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 25, 2015. The amount of cash available for distribution that we generated during the year ended December 31, 2012 on a pro forma basis would have been sufficient to pay 100% of the aggregate minimum quarterly distribution on all common units, and 16.4% of the aggregate minimum quarterly distributions on our subordinated units for that period. In addition, 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 natural gas prices, a decline in 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 1,267 rigs in February 2015. In the fourth quarter of 2014 and continuing into 2015, the price of crude oil has dropped substantially. If crude oil prices do not recover, or take longer to recover than anticipated, exploration and production companies in the regions we conduct W&ES may reduce capital spending on maintaining or growing production. W&ES constitutes approximately 6% of our revenue for the year ended December 31, 2014. Therefore, a continued decrease in drilling activity or hydraulic fracking could have an adverse effect on our revenue and profitability.

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:

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- 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 PI&IS segment are substantial, which will reduce our borrowing capacity for other purposes and reduce our cash available for distribution.

PI&IS 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 PI&IS, 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 waste management activities and pipeline inspection and integrity activities.

Our business is largely dependent on the willingness of customers to outsource the treatment of their water and environmental services and pipeline inspection and integrity activities. Currently, many oil and natural gas producing companies own and operate waste treatment, recovery and SWD facilities, and some producers recycle saltwater on-site. In addition, 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. Furthermore, 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, such as pigging and aerial surveys. Our current customers could decide to process and dispose of their waste internally or inspect and perform integrity activities on their own pipeline systems, 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 W&ES and PI&IS. Other companies offer similar third-party saltwater disposal or pipeline inspection and integrity services 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 ceasing to deliver saltwater to our SWD facilities or by choosing to not use us to provide pipeline inspection and integrity management services. Therefore, there is a heightened risk that our customers may decide not to dispose of their saltwater disposal through us or use our inspection and integrity services. The failure of customers to continue to use our services could adversely affect our operations, financial condition 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 78% and 80% of our consolidated revenue for the year ended December 31, 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 year ended December 31, 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 PI&IS. Revenues from these customers resulted from inspection operations, which are activities conducted by our PI&IS 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.

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 of 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 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.

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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 22% of our revenue for the year ended December 31, 2014 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.

CEP LLC’s historical results for 2012 represents the results of only one of the water and environmental services companies we have acquired. The results of the other water and environmental services company that we acquired are only shown since the end of 2012. Furthermore, our full 2012 and the period prior to June 26, 2013 historical financial and operating data does not include PI&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 and that of CEP LLC 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 in both of our segments. 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;
- impact of the Affordable Care Act and employee insurance;
- limitations with systems and technology;
- safety and training;
- ability to recruit, train and retain personnel and managers;
- ability to obtain permits for expanded operations;
- access to debt and equity capital on attractive terms; and
- long lead times associated with acquiring equipment and building any new facilities.

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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 expect to 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.

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.

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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 CES LLC, an arrangement with an affiliate of SBG Energy Services, LLC. We may also enter into other arrangements with third parties in the future. SBG Energy Services, LLC has, and 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, including CES LLC, may involve risks not otherwise present without a partner, including, for example:

- our CES LLC partner shares certain blocking rights over transactions between CES LLC and its affiliates, including us;
- our partner may take actions contrary to our instructions or requests or contrary to our policies or objectives;
- although we control CES LLC, we owe contractual duties to CES LLC and its respective other owners, which may conflict with our interests and the interests of our unitholders; and
- disputes between us and our partner may result in delays, litigation or operational impasses.

The risks described above or any failure to continue our joint venture 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 our $120 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 million to $200 million. CEP-TIR and TIR LLC are also co-borrowers and co-guarantors under our credit agreement. 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 its 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 our investment. 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, 2014, we had $77.6 million of indebtedness outstanding under our credit agreement. In February 2015, we borrowed an additional $52.6 million to acquire the remaining non-controlling interest in the TIR Entities. 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.

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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. As of December 31, 2014, we have the required state and federal permits across the two states where we operate our SWD facilities. 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.

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 $33 thousand on our balance sheet related to our future closure obligations of our SWD facilities as of December 31, 2014. 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. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing. SDWA regulates the underground injection of substances through the UIC program and exempts hydraulic fracturing from the definition of "underground injection." 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, were proposed in recent sessions of Congress. The U.S. Congress may consider similar SDWA legislation in the future.

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In addition, the EPA, has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels in those states where EPA is the permitting authority. Also, in November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. Further, on October 21, 2011, the EPA announced its intention to propose federal Clean Water Act regulations governing wastewater discharges from hydraulic fracturing and certain other natural gas operations. In addition, the DOI published a revised proposed rule on May 16, 2013 that would update existing regulation of hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water. The DOI is expected to issue the final rule in 2015.

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. In addition, some local governments, most recently in Colorado, have passed or adopted ordinances and other laws that severely restrict and in some instances totally ban the practice within these jurisdictions.

The EPA is conducting a study of the potential impacts of hydraulic fracturing activities on drinking water. The EPA issued a Progress Report in December 2012 and a final draft report that compiles the results of various research projects is expected to be released in 2015 for peer review and public comment. 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 or 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 supply. In response to continuing drought conditions in 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.

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 injection of saltwater and other fluids into belowground disposal wells triggers seismic activity in certain areas. Recent seismic events have been observed in some areas where deep well fluid injection of drilling or hydraulic fracturing saltwater has taken place. Some scientists believe the increased seismic activity may result from deep well fluid injection of drilling or hydraulic fracturing saltwater. Some states, including Texas, Oklahoma and Ohio, 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. Similar rules may be expected to be promulgated by the Oklahoma Corporation Commission (OCC). The OCC recently posted guidance for wells injecting into the Arbuckle formation. OCC is watching for indications that salt water injection may be contributing to significant seismic events and has recently temporarily shut in another producer's water disposal well due to a nearby 4.0 magnitude earthquake. 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 and worker health and safety 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, worker health and safety, waste management, waste disposal, and transportation of waste and other materials. In the U.S., such laws and regulations include the RCRA, CERCLA, the Clean Water Act, SDWA, CAA, OPA, and OSHA, and analogous state laws. In Canada, industrial and natural resource extraction is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Both federal and provincial governments can and do exercise regulatory responsibilities. Principal federal legislation includes the Canadian Environmental Assessment Act, the Fisheries Act, the Prosperity Act, the Canadian Environmental Protection Act, the Transportation of Dangerous Goods Act, and the Hazardous Products Act. The majority of industrial and natural resource extraction activities occur in Western Canada and Ontario where we currently operate, as well as in Quebec and Newfoundland and Labrador. The principal provincial laws and regulations which affect where we currently operate include, in Alberta, the Alberta Land Stewardship Act, the Environmental Protection and Enhancement Act, and the Climate Change and Emissions Management Act. In British Columbia, these include the Environmental Management Act, the Environmental Assessment Act, the Oil and Gas Activities Act, the Environmental Protection and Management Regulation, the Carbon Tax Act, the Greenhouse Gas Reduction (Cap and Trade) Act, and the Oil and the Water Protection Act. In Saskatchewan, these include the Oil and Gas Conservation Act, and the Management and Reduction of Greenhouse Gasses Act. In Ontario, the principal provincial laws include the Environmental Protection Act, the Green Energy Act, the Ontario Water Resources Act and the Environmental Assessment Act. 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, the imposition of specific standards addressing worker protection, and the imposition of substantial liabilities and remedial obligations for pollution or contamination resulting from our and our customer’s operations.

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, the imposition of specific standards addressing worker protection, 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 and 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 customers' operations may be subject to existing and future CAA permitting and regulatory requirements that could have a material effect on their operations. For example, on August 16, 2012, the EPA published final rules that establish new air emission controls for oil and natural gas production and natural gas processing operations under the CAA and/or Canadian climate change control. The EPA's rule package requires new standards on all hydraulically-fractured wells constructed or refractured after January 1, 2015. 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. In Canada, Alberta's Climate Change and Emissions Management Act as well as British Columbia's Greenhouse Gas Reduction (Cap and Trade) Act impose requirements to reduce emission intensity, and in the case of the Greenhouse Gas Reduction (Cap and Trade) Act, impose absolute caps on greenhouse gas emissions. Saskatchewan's Management and Reduction of Greenhouse Gases Act aims to adopt a goal of a 20% reduction in greenhouse gas emissions from 2006 levels by 2020. Certain other provinces including British Columbia, Manitoba and Ontario are parties to the Western Climate Initiative, which has established a goal to reduce greenhouse gas emissions in the region by 15% below 2005 levels, by 2020. Given the evolving nature of the debate related to climate control and control of greenhouse gases, compliance with these rules could result in significant costs to our customers, which may have an indirect adverse impact on our business.

Numerous governmental authorities, such as the EPA, and analogous state and provincial agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly corrective actions or costly pollution control measures. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions limiting or preventing some or all of our and our customer's operations. 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.

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 in both the U.S. and Canada may 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.

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The effect of changes to healthcare laws in the United States may materially increase the healthcare costs attributable to us and, to the extent we are responsible for those increased costs, negatively impact our financial results.

The Patient Protection and Affordable Care Act as well as other healthcare reform legislation considered by federal and state legislators could significantly impact our business. These health care reform laws require employers such as us, to provide health insurance for all qualifying employees or pay penalties for not providing coverage. We cannot predict the effects this legislation or any future state or federal healthcare legislation or regulation will have on our business because of the breadth and complexity of the legislation and because many of the rules, reforms and regulations required to implement these laws have not yet been adopted. However, we expect this legislation to materially increase the employee healthcare and other related costs attributable to us to the extent we become responsible for the full amount of our entire general and administrative services under our amended and restated omnibus agreement, which currently limits our corporate general and administrative services to an annual administrative fee of $4.04 million, as adjusted for inflation. As the provisions of this legislation are phased in over time, the resulting changes to our healthcare cost structure and any inability to effectively modify our programs and operations in response to this legislation could have a material adverse effect on our business, financial conditions and results of operations.

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.

In response to certain scientific studies suggesting that emissions of GHGs, including carbon dioxide and methane, are contributing to the warming of the Earth’s atmosphere and other climatic conditions, the U.S. Congress has 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 either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time.

In addition, in December 2009, the EPA determined that emissions of carbon dioxide, methane and certain other GHGs endanger public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. The EPA has already adopted two sets of rules regulating GHG emissions under the CAA, one of which requires a reduction in emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources, both of which became effective in January 2011. The EPA’s rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent the EPA from implementing or requiring state environmental agencies to implement the rules. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified GHG emission sources in the U.S., including oil and natural gas producer operations, on an annual basis. Additionally, on September 20, 2013, the EPA proposed New Source Performance Standards for Greenhouse Gas emissions from Electric Utility Generating Units and issued the proposed Clean Power Plan in June 2014 that would, among other things, limit GHG emissions from existing coal-fired power plants. These actions represent increased government regulation of climate change-related issues and GHG emissions. We cannot predict which areas, if any, the EPA may choose to regulate with respect to GHG emissions next.

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, state or local 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, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If 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.

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. The designation of previously unidentified endangered or threatened species under such laws may affect our and our customers’ operations.

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For example, the federal government is considering listing the greater sage-grouse, a species whose natural habitats coincide with some of our areas of operation and the areas of operation of some of our customers. Currently, greater sage-grouse are found in Washington, Oregon, Idaho, Montana, North Dakota, eastern California, Nevada, Utah, western Colorado, South Dakota and Wyoming. The U.S. Fish and Wildlife Service, or "Service", has concluded that the greater sage-grouse warrants protection under the ESA; however, the Service has determined that proposing the species for protection is precluded by the need to take action on other species facing more immediate and severe extinction threats. As a result, the greater sage-grouse will be placed on the list of species that are candidates for ESA protection. The lesser prairie-chicken, which currently occupies a five-state range that includes Texas, New Mexico, Oklahoma, Kansas and Colorado was also listed as threatened in March 2014. The Service will review the status of these species annually, as it does with all candidate species, and will propose the species for protection when funding and workload priorities for other listing actions allow. Additionally, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the 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 Service's 2017 fiscal year. Another species, the dunes sagebrush lizard, which is found only in the active and semi-stable shinnery oak dunes of southeastern New Mexico and adjacent portions of Texas, was a candidate species for listing under the ESA by the Service for many years. On June 13, 2012, however, the Service declined to list the species as endangered under the ESA, and it is no longer a candidate species. Nevertheless, the species remains listed as endangered by the New Mexico Department of Game and Fish, and thus is subject to certain protections under New Mexico state law.

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

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

Our activities are subject to a wide range of national, state and local occupational health and safety laws and regulations. These health and safety laws are subject to change, as are the priorities of those who enforce them. 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 important to our clients and can materially impact our business.

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.

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 customers, employees and regulators. In particular, our customers may elect not to purchase our services if they view our safety record as unacceptable, which could cause us to lose customers and substantial revenues.

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.

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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.

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 TIR LLC, the inspector is considered an employee of TIR LLC and is eligible for workers' compensation claims if the inspector is injured or killed while working for TIR LLC. As the inspectors generally travel to and from projects in their own vehicles, TIR LLC may be responsible for workers compensation claims or third-party claims arising out of vehicle accidents, which could negatively affect our results of operation.

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. 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.

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.

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 three other managed facilities. 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.

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.

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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 PI&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 both of 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, PI&IS is dependent on the TIR Entities' specialized inspectors, who must undergo specific training prior to performing inspection 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. In addition, the U.S. customers in PI&IS could choose to hire TIR LLC's 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 President and Chief Executive Officer, 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.

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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.

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 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 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, or “Section 404”. For example, Section 404 requires, among other things, us 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 the TIR Entities and one for the remainder of our business. 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 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.

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.

Holdings and its affiliates own a 58.8% 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:

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

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

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

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

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

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

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."

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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 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.

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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 $1.01 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 58.8% of the common units and subordinated units (excluding common units purchased by certain of our officers, directors and other affiliates in our IPO). 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.

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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.

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 22.7% of our common units (excluding any common units purchased by certain of our officers, directors and other affiliates in our IPO). 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 58.8% of our outstanding common units (excluding any common units purchased by certain of our officers, directors and other affiliates in our IPO) 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.

There are only 4,312,500 publicly traded common units held by our 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.

Tax Risks

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, 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 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 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 federal income tax purposes or otherwise subject us to taxation as an entity.

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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. Because of widespread state budget deficits and other reasons, several states 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 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, from time to time, members of Congress and the President propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships, including the elimination of partnership tax treatment for publicly traded partnerships. Any modification to the 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 exception for us to be treated as a partnership for 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 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 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 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.

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 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.

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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.

The TIR Entities conduct activities that may not generate qualifying income, and we conduct these activities in a separate subsidiary that is treated as a corporation for U.S. federal income tax purposes. Corporate federal income tax paid by this subsidiary reduces 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 portion of our business related to these operations in a separate subsidiary that is treated as a corporation for U.S. federal income tax purposes. We estimate that these operations will represent approximately 9% of the combined gross margin of the PI&IS segment for 2015.

This corporate subsidiary 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 TIR LLC. If we do not obtain a favorable ruling from IRS, we will be required to continue to conduct these activities in a subsidiary that is treated as a corporation for U.S. federal income tax purposes and is 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 TIR LLC. 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 promulgated under the Internal Revenue Code and referred to as "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 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 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 use of this proration method may not be permitted under existing Treasury Regulations. However, the U.S. Treasury Department has issued proposed regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose common units are 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 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 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 will adopt certain valuation methodologies and monthly conventions for federal income tax purposes that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner for purposes of determining our incentive distributions. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of taxable income, gain, loss and deduction between our general partner, in its capacity as holder of our incentive distribution rights, and certain of our unitholders.

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

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 federal income tax purposes.

We will be considered to have technically terminated our partnership for 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 federal income tax purposes, but instead we would be treated as a new partnership for 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 federal income taxes, our unitholders will likely be 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 will likely be 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.

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ITEM 2. PROPERTIES

Our Properties

As of December 31, 2014, 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 51.0% of CES, a management and development company that owns a 25.0% non-controlling interest in this SWD facility.
(3) Some facilities are constructed on land that is leased under long term arrangements.

In addition to the above properties, we also manage two other SWD facilities in the Bakken Shale region.

Our corporate headquarters are located at 5727 S. Lewis Avenue, Suite 500, Tulsa, Oklahoma 74105. We lease 7,279 square feet of general office space at our corporate headquarters. The lease expires in February 2018 unless terminated earlier under certain circumstances specified in our lease.

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.

Fenley v. TIR LLC

On February 2, 2015, a former inspector for TIR LLC filed a putative collective action lawsuit alleging that TIR LLC failed to pay a class of workers overtime in compliance with the Fair Labor Standards Act (“FLSA”) titled Fenley v. TIR LLC in the United States District Court for the District of Kansas. The plaintiff alleges he was a non-exempt employee of TIR and that he and other potential class members were not paid overtime in compliance with the FLSA. The plaintiff seeks to proceed as a collective action and to receive unpaid overtime and other monetary damages, including attorney’s fees. On February 24, 2015, TIR LLC filed a Motion to Dismiss this case, based upon improper venue. We have retained counsel with experience in cases of this nature and intend to vigorously defend this litigation.

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.

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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."

Our common units began trading on January 15, 2014, at an initial offering price of $20.00 per common unit. Prior to that time, there was no public market for our common units. On December 31, 2014, the closing price for the common units was $14.30 per unit and there were approximately 3,750 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.

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

	2014			
Quarter Ended	High	Low	Distribution (a)	
March 31	$26.00	$19.55	$0.301389	(b)
June 30	24.97	21.65	0.396844	
September 30	25.78	22.22	0.406413	
December 31	24.93	11.54	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.

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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.

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.

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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, 2014.

Unregistered Sales of Equity Securities

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

Issuer Purchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA

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

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 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.

There is a lack of comparability for the information presented for our Predecessor for 2012 as it includes the activity of the four subsidiaries distributed to Holdings prior to the contribution of CEP LLC to the Partnership and does not reflect the fair value of assets and liabilities recorded by the Partnership when the Predecessor was acquired by CEP LLC (see Note 4 to the Consolidated Financial Statements).

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 (3)	
	Year Ended December 31, 2014	Year Ended December 31, 2013 (1) Recast	Period from March 15 (Inception) through December 31, 2012 (2) Recast	Year Ended December 31, 2012	Period from June 1 (Inception) through December 31, 2011
	(in thousands, except operational data)				
Income Statement Data					
Revenues	$404,418	$249,133	$619	$12,203	$2,944
Costs of services	355,355	213,690	309	3,662	503
Gross margin	49,063	35,443	310	8,541	2,441
General and administrative expense	21,321	12,467	2,056	477	138
Depreciation, amortization and accretion	6,345	5,164	99	1,398	123
Impairments	32,546	4,131	-	-	-
Operating income (loss)	(11,149)	13,681	(1,845)	6,666	2,180
Interest expense, net	3,208	4,000	-	111	35
Offering costs	446	1,376	-	-	-
Net income (loss)	(15,179)	4,355	(1,845)	6,595	2,162
Net income attributable to non-controlling interests	4,973	22	-	-	-
Net income (loss) attributable to partners/controlling interests	(20,152)	4,333	-	-	-
Balance Sheet Data - Period End					
Total assets	$189,842	$240,590	$79,990	$27,588	$14,476
Long-term debt	77,600	75,000	-	2,314	2,798
Total parent net investment and owners' equity	100,428	135,547	77,746	24,769	9,265
Cash Flows Data					
Cash flows from operating activities	$13,016	$7,154	$(2,244)	$7,246	$1,106
Cash flows from investing activities	(2,286)	5,779	(65,613)	(15,236)	(10,860)
Cash flows from financing activities	(16,030)	13,363	68,341	8,425	9,901
Cash distributions per unit (subsequent to IPO) (4)	1.51	-	-	-	-
Capital expenditures	2,286	4,329	65,613	15,236	10,860
Other financial data					
Adjusted EBITDA	$28,499	$23,110	$(1,746)	$8,104	$2,320
Adjusted EBITDA attributable to partners/controlling interests	19,841	23,079	(1,746)	8,104	2,320
Operational data					
Total barrels of saltwater disposed (in thousands)	19,066	19,541	551	8,674	1,641
Average revenue per barrel	$1.18	$1.14	$1.12	$1.41	$1.79
Average number of inspectors	1,535	1,706	-	-	-
Average revenue per inspector per week	$4,771	$4,952	-	-	-

(1) Activity for the year ended December 31, 2013 includes operations of PI&IS from the June 26, 2013 acquisition date through the end of the year.

(2) 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.

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

(4) Includes February 2015 distribution related to the quarter ended December 31, 2014.

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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, and non-cash allocated expenses, 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 definitions 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.

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

	Cypress Energy Partners, L.P.			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013 (1) Recast	Period from March 15 (Inception) through December 31, 2012 (2)	Year Ended December 31, 2012
	(in thousands)			
Reconciliation of Net Income (Loss) to Adjusted EBITDA				
Net income (loss)	$(15,179)	$4,355	$ (1,845)	$ 6,595
Add:				
Interest expense	3,208	4,000	-	111
Depreciation, amortization and accretion	6,513	5,261	99	1,398
Impairments	32,546	4,131	-	-
Income tax expense	468	15,237	-	-
Offering costs	446	1,376	-	-
Non-cash allocated expenses	497	-	-	-
Less:				
Gain on reversal of contingent consideration	-	11,250	-	-
Adjusted EBITDA	$28,499	$23,110	$ (1,746)	$ 8,104
Adjusted EBITDA attributable to non-controlling interests	8,658	31		
Adjusted EBITDA attributable to partners / controlling interests	$19,841	$ 23,079		
Adjusted EBITDA attributable to general partner	1,651			
Adjusted EBITDA attributable to limited partners	$18,190			

(1) Activity for the year ended December 31, 2013 includes operations of PI&IS 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.

(2) 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.

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The following table presents a reconciliation of net income (loss) and net cash provided by (used in) operating activities to Adjusted EBITDA, as applicable, for each of the periods indicated.

Reconciliation of Net Cash Provided by (Used in) Operating Activities to Adjusted EBITDA	Year Ended December 31, 2014	Year Ended December 31, 2013(1)	Period from March 15 (Inception) through December 31, 2012 (2)	Predecessor Year Ended December 31, 2012
		Recast	***Recast***	
	(in thousands)			
Cash flows provided by (used in) operating activities	$13,016	$7,154	$(2,244)	$7,246
Changes in accounts receivable	(6,650)	8,793	741	(219)
Changes in inventory, prepaid expenses and other assets	933	(283)	12	(353)
Changes in accounts payable and accrued liabilities	2,964	1,910	(255)	(175)
Change in income taxes payable	15,612	(15,816)	-	-
Interest expense (excluding non-cash amortization)	2,494	2,781	-	(111)
Offering costs	446	1,376	-	-
Income tax expense	468	15,237	-	-
Stock compensation	(785)	(90)	-	-
Other	1	2,048	-	-
Adjusted EBITDA	$28,499	$23,110	$(1,746)	$8,104

(1) Activity for the year ended December 31, 2013 includes operations of PI&IS from the June 26, 2013 acquisition date through the end of the year.

(2) 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.

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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 and Integrity Services ("PI&IS") 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.

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 that provides saltwater disposal and other water and environmental services and pipeline inspection and integrity services. Through W&ES, 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. We also manage three other SWD facilities in the Bakken Shale region, one of which we have a 25% ownership interest. W&ES customers are oil and natural gas exploration and production companies and trucking companies operating in the regions that we serve. Through PI&IS, we provide independent pipeline inspection and integrity services to various energy, public utility and pipeline companies. In both of these 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 and reduce their operating costs.

How We Generate Revenue

We generate revenue in W&ES 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 volume of 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. Through our 51.0% ownership interest in CES LLC, we also generate revenue managing SWD facilities for a fee.

We generate revenue in PI&IS primarily by providing inspection and integrity 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 PI&IS 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. We bill our customers on a per inspector basis, including per diem charges, mileage and other reimbursement items.

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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:

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

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 22% and 25% of our segment revenue for the years ended December 31, 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.

Inspector Headcount

The amount of revenue we generate in PI&IS 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.

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. 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 over time to avoid significant variability in our maintenance capital expenditures, downtime and minimize their impact on our cash flows.

Employee-or-contractor-related costs and per diem expenses are the primary costs of services components in PI&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.

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

Under our amended and restated omnibus agreement, Holdings charges us an annual administrative fee of $4.0 million (payable in equal quarterly installments) for the provision of certain 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 our general partner 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 Statement of Operations as incremental general and administrative expense and treated as an equity contribution.

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, which we estimate to be approximately $2.0 million. 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 and amortization. Depreciation and amortization expense consists of our estimate of the decrease in value of the assets capitalized in property, plant and equipment as a result of using the assets throughout the year. Depreciation is 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 82% and 83% of the cost basis of our fixed assets as of December 31, 2014 and 2013 respectively, and have useful lives of 5 to 15 years.

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, and we define Adjusted EBITDA as net income, plus interest expense, depreciation and amortization expenses, income tax expense, offering costs, impairments and non-cash allocated expenses, less the gain on the reversal of contingent consideration. Although we have not quantified distributable cash flow on a historical basis, we intend to use distributable cash flow, which we define 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 headcount of PI&IS varies 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.

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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

W&ES

Crude oil prices declined sharply during the six months ended December 31, 2014 (the spot price for NYMEX West Texas Intermediate ("WTI") crude oil at Cushing, Oklahoma declined from $106.06 per barrel at July 1, 2014 to $53.45 per barrel at December 31, 2014). Subsequently, WTI has further declined to approximately $47.00 per barrel at March 25, 2015 and Bakken Clearbrook, which trades at a discount to WTI, was trading at approximately $42.00 per barrel. In our W&ES segment, 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 the reaction of oil and gas producers in the vicinity of our facilities to declining oil and/or gas prices.

Many producers have announced material and significant cuts in their 2015 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, will lead to lower water volumes, reduced skim oil volumes and pricing pressures. Many of our E&P customers have requested 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 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 are less impacted than many competitors. However, we are clearly being impacted on all metrics. We are focused on reducing operating costs and identifying operating efficiencies in an effort to offset the financial impact of declining 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. We also manage some third party facilities, who are also being impacted by the facts above leading to lower management fee revenue.

PI&IS

Demand remains solid for our pipeline inspection and integrity services in a very large market with many customer prospects that we do not currently serve. We have strengthened our management team and focused on non-destructive testing services as we continue to look at a number of other new lines of business to serve our existing customers. The majority of our clients are public investment grade companies with long planning cycles leading to healthy backlogs of new long-term projects in addition to maintaining their existing pipeline networks that also require inspection. We have also only begun to penetrate the public utility company ("PUC") segment of the industry that brings natural gas to homes and businesses. We believe that with increasing regulatory requirements and the aging U.S. and Canadian pipeline infrastructure that the PI&IS business is more insulated from changes in commodity prices in the near term. A prolonged depression in oil and natural gas prices could lead to a downturn in demand for our services over time.

We are aggressively pursuing growth opportunities in both of our business segments through both acquisitions and organic growth. Additionally, we are continually looking for new talent to strengthen our management team as we continue to grow.

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 to 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.

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).

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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 PI&IS segment.

During the years ended December 31, 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 $12.8 and $3.4 million during the years ended December 31, 2014 and 2013, respectively, for these assets. 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.

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.

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Identifiable Intangible Assets

Our recorded identifiable intangible assets primarily include customer lists and trademarks and trade names. Identifiable intangible assets with finite lives are amortized 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 year ended December 31, 2014. During the year ended December 31, 2013, the partnership determined that one of its trade names in PI&IS 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.

Goodwill

At December 31, 2014 and 2013, the Partnership had $55.6 and $75.5 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 W&ES and PI&IS 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 PI&IS reporting unit, we performed a qualitative assessment to determine whether the fair value of the reporting unit was more likely than not to be less than its carrying value. 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 assessment on this reporting unit indicated the fair value of the reporting unit exceeded the carrying value and the reporting unit was not at risk for a potential goodwill impairment.

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.

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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 forecast used in this analysis makes certain assumptions about future pricing, volumes and expected maintenance capital expenditures. Assumptions are also made for a “normalized” perpetual growth rate 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 critical 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 the reporting units and other intangible assets, it is possible a material change could occur.

As a result of our valuation, 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 some of the regions in which we operate which has resulted in declining volumes and increased pricing pressure. The fourth quarter decline in oil prices has 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. Lower oil prices will also directly impact revenues as oil sales have historically represented in excess of 20% of our W&ES revenues.

Depreciation Methods, Estimated Useful Lives of Property

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 asset. 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 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.

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

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:

- 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.

- The effective date of the acquisition of our 51% ownership of CES LLC was October 1, 2013; accordingly, the financial data presented does not reflect the results of operations of CES LLC prior to that date.

- 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, 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 the 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. Borrowings under the credit agreement were 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.

- CEP LLC had no operations prior to an acquisition completed on December 3, 2012. Financial data for CEP LLC for the period from Inception through December 31, 2012, is included in a separate column in the tables below.

- The financial statements of the Predecessor include the results of operations of certain limited liability companies that were not contributed to the Partnership.

- General and administrative expenses of the Predecessor's SWD facilities represent expenses associated with those assets as stand-alone businesses and do not represent sales and general and administrative expenses we incurred to operate those assets as part of a larger business. Operating expenses associated with CEP LLC's headquarters office, primarily consisting of management salaries and general and administrative expenses, are not reflected in the results of its Predecessor.

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

	Cypress Energy Partners, L.P.			Predecessor
	2014	2013 (a) Recast	2012	2012
	(in thousands)			
Revenues	$404,418	$249,133	$619	$ 12,203
Costs of services	355,355	213,690	309	3,662
Gross margin	49,063	35,443	310	8,541
Operating costs and expense:				
General and administrative	21,321	12,467	2,056	477
Depreciation, amortization and accretion	6,345	5,164	99	1,398
Impairments	32,546	4,131	-	-
Operating (loss) income	(11,149)	13,681	(1,845)	6,666
Other income (expense):				
Interest expense, net	(3,208)	(4,000)	-	(111)
Offering costs	(446)	(1,376)	-	-
Gain on reversal of contingent consideration	-	11,250	-	-
Other, net	92	37	-	40
Net (loss) income before income tax expense	(14,711)	19,592	(1,845)	6,595
Income tax expense	468	15,237	-	-
Net (loss) income	(15,179)	4,355	$(1,845)	$ 6,595
Net income attributable to non-controlling interests	4,973	22		
Net (loss) income attributable to partners / controlling interests	(20,152)	$4,333		
Net income attributable to general partner	149			
Net loss attributable to limited partners	$(20,301)			

(a) Activity for the year ended December 31, 2013 includes operations of PI&IS from the June 26, 2013 acquisition date through the end of the year.

See the detailed discussion of revenues, cost of sales, 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 Part II of this Form 10-K for more information about our recasted Consolidated Financial Statements for prior periods.

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The following is a discussion of significant changes in the non-segment related corporate other income and expenses for the years ended December 31, 2014, 2013 and 2012.

Interest expense. Interest expense in 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 as well as the fact that 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, 2014 and 2013 was $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. Interest expense in 2012 represents interest expense associated with the construction of the acquired SWD facilities as incurred by our Predecessor.

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 2012.

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 2014 of $0.4 million includes income taxes related to one taxable corporate subsidiary in the United States and two taxable corporate subsidiaries in Canada in our PI&IS 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.

Net income attributable to non-controlling interests. Non-controlling interests in 2014 include a 49.9% interest in the TIR Entities (effectively our PI&IS segment) that is owned by certain affiliates of Holdings, a 49% interest in one consolidated subsidiary in our W&ES segment, CES LLC, as well as a 51% interest of a subsidiary of TIR LLC, that was created in 2014 and is consolidated for reporting purposes. The non-controlling interest holders of the TIR Entities are charged directly for certain financing expenses of the Partnership. These charges are reflected as a direct reduction of their proportionate share of net income. Non-controlling interests in 2013 only include the 49% interest in CES LLC.

Segment Operating Results

W&ES

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	(Recast) 2013	% of Revenue	Change	% Change
	(in thousands, except per barrel data)					
Revenue	$22,416		$22,232		$184	1 %

Costs of services	8,617		7,347		1,270	17 %
Gross margin	13,799	62 %	14,885	67 %	(1,086)	(7)%
General and administrative expense	3,587	16 %	3,292	15 %	295	9 %
Impairments	32,546		3,429		29,117	849 %
Depreciation, amortization and accretion	3,806		3,837		(31)	(1)%
Operating income	$(26,140)	-117 %	$4,327	19 %	$(30,467)	(704)%
Operating Data						
Total barrels of saltwater disposed	19,066		19,541		(475)	(2)%
Average revenue per barrel disposed (a)	$1.18		$1.14		0.04	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 include flowback, produced water, residual oil sales and management fees) by the total barrels of saltwater disposed.

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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. 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. This decline is offset somewhat by higher revenues.

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The following table summarizes the operating results of our W&ES segment for the years ended December 31, 2013 and 2012.

	Years Ended December 31,					
	(Recast) 2013	% of Revenue	Predecessor 2012	% of Revenue	Change	% Change
	(in thousands, except per barrel data)					
Revenue	$22,232		$ 12,203		$10,029	82 %
Costs of services	7,347		3,662		3,685	101 %
Gross margin	14,885	67 %	8,541	70 %	6,344	74 %
General and administrative expense	3,292	15 %	477	4 %	2,815	590 %
Impairments	3,429		-		3,429	
Depreciation, amortization and accretion	3,837		1,398		2,439	174 %
Operating income	$4,327	19 %	$ 6,666	55 %	$(2,339)	(35)%
Operating Data:						
Total barrels of saltwater disposed	19,541		8,674		11,677	148 %
Average revenue per barrel disposed (a)	$1.14		$ 1.41		(0.41)	(27)%
Revenue variance due to barrels disposed					$18,118	
Revenue variance due to revenue per barrel					(8,089)	

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

Revenue. W&ES revenues were $22.2 million for the year ended December 31, 2013, compared to its Predecessor’s $12.2 million for the same period of 2012, an increase of 82%. The overall increase in saltwater disposal revenues was primarily driven by an increase in saltwater disposal volumes from 8.7 million barrels for the year ended December 31, 2012 to 19.5 million barrels for the same period in 2013. This increase in saltwater disposal volumes was associated with the fact that only three of six Predecessor wells were operational for the full year of 2012 as the other three came on line at various times throughout the year. In addition, we acquired four wells in December 2012 that are not reflected in the Predecessor’s results. The increase in volumes was offset somewhat by a decline in average pricing across the wells from $1.41 per barrel of disposed saltwater for 2012 to $1.14 per barrel in 2013. The decline in revenue per barrel was primarily attributable to our decision to reduce pricing in the Bakken Shale region due to competitive pressures and to the addition of two wells in the Permian Basin which have lower average pricing relative to the Bakken wells due to regional market differences and lower operating expenses. The Bakken Shale region has differential pricing between flowback and produced water.

Costs of Services. W&ES costs of services were $7.3 million for the year ended December 31, 2013, compared to its Predecessor’s costs of sales of $3.7 million for the same period of 2012, an increase of 101%. This increase was primarily attributable to the difference in the number of wells operating between the periods. Incremental costs of sales attributable to wells not in operation at December 31, 2012 were $3.5 million.

Gross Margin. Gross margin was $14.9 million for the year ended December 31, 2013, compared to $8.5 million for the same period of 2012, an increase of $6.3 million or 74%. Gross margin as a percentage of total revenues declined to 67% for the year ended December 31, 2013 from 70% for the year ended December 31, 2012. The decline in gross margin as a percentage of revenue is primarily a result of higher costs of sales attributable to higher repair and maintenance expenses due to the fact that most of the wells did not come on line until 2012 and had minimal repairs and maintenance in the first year of operation, as well as lower average revenue per barrel disposed.

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General and Administrative Expenses. General and administrative expenses were $3.3 million for the year ended December 31, 2013, compared to $0.5 million for the Predecessor for the same period in 2012, an increase of 590%. General and administrative expenses increased by $2.8 million, primarily attributable to $0.5 in incremental expenses associated with operating our wells acquired on December 3, 2012 for a full year and $1.8 million, attributable to corporate office overhead expenses. The increase in the corporate activities was largely attributable to an increase in professional services of $1.3 million incurred primarily in relation to legal and accounting services. The remaining corporate activity costs were associated with corporate salaries of $0.4 million that were not included in the 2012 Predecessor results. The general and administrative expenses associated with the Predecessor wells increased $0.5 million due to the variable costs of running the facilities with higher volumes of saltwater disposed primarily associated with the start date of wells that commenced operations in 2012.

Impairments. During the year ended December 31, 2013, we recorded an impairment charge at one of our SWD facilities totaling $3.4 million.

Depreciation, Amortization and Accretion Expenses. Depreciation and amortization expenses were $3.8 million for the year ended December 31, 2013, compared to the Predecessor's $1.4 million for the same period in 2012, an increase of 174%. Depreciation and amortization increased primarily as a result of having more SWD wells and a higher depreciable basis in the SWD wells acquired from the Predecessor on December 31, 2012.

Operating Income. We recorded operating income of approximately $4.3 million for the year ended December 31, 2013, compared to our Predecessor's operating income of $6.7 million for the same period in 2012, a decrease of 35%. This decrease was primarily the result of higher segment gross margin from the increased number of well sites of $6.3 million offset by higher operating expenses, primarily depreciation and amortization ($2.4 million increase) and general and administrative expenses ($2.8 million increase) associated with the expanded operations, as well as an impairment charge of $3.4 million.

PI&IS

The following table summarizes the operating results of our PI&IS 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 operating data)					
Revenue	$382,002		$226,901		$155,101	68 %
Costs of services	346,738		206,343		140,395	68 %
Gross margin	35,264	9 %	20,558	9 %	14,706	72 %
General and administrative expense	17,734	5 %	9,175	4 %	8,559	93 %
Impairments	-		702		(702)	(100)%
Depreciation, amortization and accretion	2,539		1,327		1,212	91 %
Operating income	$14,991	4 %	$9,354	4 %	$5,637	60 %
Operating Data:						
Average number of inspectors	1,535		1,706	(b)	(171)	(10)%
Average revenue per inspector per week	$4,771		$4,952	(b)	$(181)	(4)%

(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.

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 9%.

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.

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Liquidity and Capital Resources

We anticipate making significant growth capital expenditures in the future, including acquiring new SWD facilities and pipeline inspection companies or expanding our existing assets and offerings in our current operations. In addition, the working capital needs of the PI&IS segment are substantial. Please read "Risk Factors — Risks Related to Our Business — The working capital needs of the PI&IS 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, 2014, our sources of liquidity included:

cash generated from operations, which resulted in $20.8 million in cash on the balance sheet at December 31, 2014 (inclusive of cash attributable to the non-controlling interest holders of the TIR Entities of $6.4 million);

borrowings under our credit agreement under which we had $122.4 million available for borrowings at December 31, 2014 (of which $52.6 million was utilized to acquire the non-controlling interest in the TIR Entities in February 2015); and

issuances of equity securities.

We believe that the cash generated from these sources will be sufficient to allow us to meet our requirements for minimum quarterly distributions, working capital 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 PI&IS segment since the acquisition of the TIR Entities on June 26, 2013 and therefore, may not be comparable from period to period.

	Cypress Energy Partners, L.P.			Predecessor
	Year ended December 31,			Year Ended December 31,
	2014	2013 Recast	2012 Recast	2012
		(in thousands)		
Net cash provided by (used in):				
Operating activities	$13,016	$7,154	$(2,244)	$ 7,246
Investing activities	(2,286)	5,779	(65,613)	(15,236)
Financing activities	(16,030)	13,363	68,341	8,425
Effect of exchange rates on cash	(633)	(90)	-	-
Net increase (decrease) in cash and cash equivalents	$(5,933)	$26,206	$484	$ 435

Operating activities. The growth in operating cash flow for the year ended December 31, 2014 is primarily the result of having a full year of operations for the TIR Entities as compared to slightly over six months in 2013. 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. The tax expense associated with the conversion was recorded in 2013. In addition, 2014 cash flows were favorably impacted by a decline in accounts receivable associated with lower headcounts in the fourth quarter of 2014 as well as an improvement in collections. Operating cash flows for 2012 primarily include overhead activities of the start-up corporate parent and are not comparable to 2013. Also, operating cash flows of our Predecessor are not comparable to 2013 as a result of the acquisition of the TIR Entities, the changes in number of SWD facilities and the change in structure of the entities.

Investing activities. Cash flows from investing activities are primarily impacted by acquisition activity and to a lesser extent, our capital expenditures. Investing cash flows for the year ended December 31, 2014 primarily included a $1.8 million acquisition of a SWD facility and capital expenditures of $0.5 million. Investing cash flows for 2013 include $10.8 million of cash acquired in conjunction with the acquisition of the TIR Entities offset by a $0.5 million W&ES acquisition and $3.3 million in capital expenditures primarily related to improvements and expansion at existing SWD facilities, including the completion of an additional well bore at one of our facilities. Investing cash flows for 2012 reflect our initial acquisition of our SWD facilities. Investing cash flows for our Predecessor reflect the cost of constructing additional SWD facilities.

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Financing activities. Cash flows from financing activities primarily consist of activity under our revolving credit facility net of repayments of revolving and long term financing arrangements that existed at the TIR Entities prior to the acquisition and distributions to and contributions from partners and members. 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 were proceeds from our IPO of $80.2 million which were distributed to Holdings. For the year ended 2013, cash flow from financing activities consist primarily of initial borrowings under our revolving credit facility of $75.0 which were used to repay existing obligations of the TIR entities totaling $56.5 million. In addition, we incurred debt issuance costs of $3.4 million related to our long-term obligations and $2.5 million in offering costs associated with our IPO. Financing activities for the year ended December 31, 2012 primarily consist of net contributions from our sole member used for capital expenditures and general operating purposes.

Working Capital

Our working capital was $66.0 million at December 31, 2014, compared to $62.1 and $1.9 million at December 31, 2013 and 2012, respectively. The increase in working capital from 2012 to 2013 is attributable to our acquisition of the TIR Entities. The TIR entities have substantial working capital needs throughout the year as they generally pay their inspectors 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 the TIR entities. 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 TIR entities 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.

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, 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.

Our maintenance capital expenditures and expansion capital expenditures were $0.2 million and $1.8 million in 2014, respectively. Our expansion capital expenditures primarily consisted of the acquisition of an incremental SWD facility in 2014. Prior to 2014, our historical accounting records did not differentiate between maintenance and expansion capital expenditures.

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

We and our affiliate, CEP TIR (collectively, the “Borrowers”), have a $200.0 million secured credit agreement, as co-borrowers and co-guarantors, with Deutsche Bank and BMO, acting as arrangers, consisting of a $75.0 million senior secured working capital revolving credit facility and a $125.0 million senior secured acquisition revolving credit facility. In addition, the agreement provides for an accordion feature that allows us to increase availability under the facilities by an additional $125.0 million. The facility was amended in 2014 to, among other things, increase the capacity from $120.0 million to $200.0 million and to extend the maturity date from December 2016 to December 2018.

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The obligations under our credit agreement are secured by a first priority lien on substantially all assets of the borrowers. CEP TIR's assets as of December 31, 2014 consist only of a 36.2% interest in the TIR Entities. In addition, CEP TIR agreed in its operating agreement not to borrow under the credit agreement and not to engage in any business other than owning its minority interests in the TIR Entities. Effective February 1, 2015, the Partnership acquired the remaining 49.9% interest in the TIR Entities including the 36.2% interest held by CEP TIR. In accordance with the terms of the credit agreement, CEP TIR was released as a Borrower. Certain conditions defined in the Credit Agreement limit our access to the acquisition revolving credit facility to $89.7 million of the total $97.4 million available and $15.3 million of the total available $25.0 million under the working capital revolving credit facility at December 31, 2014. Certain circumstances, such as additional acquisitions, could offset the defined limitations and provide the Partnership the opportunity to fully access the stated borrowing limitations in the Credit Agreement. Of the amount available under the acquisition revolving credit facility, $52.6 million was utilized in February 2015 to acquire the remaining interest in the TIR Entities.

We originally utilized borrowings under our credit agreement to repay and retire outstanding indebtedness under the TIR Entities' revolving credit facility and mezzanine facilities, as well as to fund income tax payments associated with the TIR Entities' conversion from a taxable corporation to a limited liability company. We intend to use the remaining borrowing capacity to fund working capital, capital expenditures, acquisitions and for general partnership purposes.

All borrowings under the credit agreement bear interest, at our option, 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 combined leverage ratio of the Borrowers, as defined in the credit agreement. For the years ended December 31, 2014 and 2013, the interest rate on these credit agreement borrowings ranged between 2.74% and 3.24% in 2014 and was 5.00% in 2013. There were no Base Rate Borrowings outstanding at December 31, 2014 or 2013. 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 payable monthly. 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, 2014, our adjusted leverage ratio was 0.94 to 1.0 and our interest coverage ratio was 9.14 to 1.0. At December 31, 2013, our total adjusted leverage ratio was 0.80 to 1.0 and our interest coverage ratio was 4.88 to 1.0.

In addition, our credit agreement restricts our ability to make distributions on, or redeem or repurchase, our equity interests, provided, however, that 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 working capital revolving credit facility by at least $5.0 million and at least $5.0 million in lender commitments are available to be drawn under the borrowing base revolving credit facility. Our calculated borrowing base was $65.3 million and $72.1 million at December 31, 2014 and 2013, respectively. The borrowing base calculation at December 31, 2013 includes $15.0 million of cash that was reserved for the payment of income taxes associated with the conversion of the TIR Inc. from a taxable entity to pass-through entities for federal income tax purposes which was paid in the first quarter of 2014. Availability under the acquisition revolving credit facility is not subject to a borrowing base calculation but is restricted by our maximum leverage calculation.

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In addition, our credit agreement contains events of default customary for facilities of this nature. 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. As described in Note 8, the Partnership was in compliance with all of its financial debt covenants as of December 31, 2014 and expects to remain in compliance throughout 2015.

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, 2014, 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	$77,600	$—	$—	$77,600	$—
Lease obligations	2,144	561	867	159	557
Total	$79,744	$561	$867	$77,759	$557

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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 2% of our consolidated revenues are derived from sales of commodities. A hypothetical change in commodity prices could result in changes in demand for our services resulting in an increase or decrease of our gross margin.

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, 2014, our exposure consists of floating interest rate fluctuations on our outstanding indebtedness under our credit agreement of $77.6 million. A hypothetical change in interest rates of 1.0% would result in an increase or decrease of our annual interest expense of approximately $0.8 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. 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.

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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, 2014 and 2013, 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, 2014. 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, 2014 and 2013, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
March 30, 2015

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CYPRESS ENERGY PARTNERS, L.P.
Consolidated Balance Sheets
As of December 31, 2014 and 2013
(in thousands, except unit data)

	December 31, 2014	December 31, 2013 Recast - Note 2
ASSETS		
Current assets:		
Cash and cash equivalents	$20,757	$26,690
Trade accounts receivable, net	54,075	60,730
Deferred tax assets	68	134
Deferred offering costs	-	2,539
Prepaid expenses and other	2,440	1,458
Total current assets	77,340	91,551
Property and equipment:		
Property and equipment, at cost	27,878	42,529
Less: Accumulated depreciation	3,538	3,711
Total property and equipment, net	24,340	38,818
Intangible assets, net	30,245	32,551
Goodwill	55,545	75,466
Debt issuance costs, net	2,318	2,149
Other assets	54	55
Total assets	$189,842	$240,590
LIABILITIES, PARENT NET INVESTMENT AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable	$2,461	$2,673
Accounts payable - affiliates	586	-
Accrued payroll and other	7,750	10,662
Income taxes payable	546	16,158
Total current liabilities	11,343	29,493
Long-term debt	77,600	75,000
Deferred tax liabilities	438	541
Asset retirement obligations	33	9
Total liabilities	89,414	105,043
Commitments and contingencies - Note 10		
Parent net investment attributable to controlling interests	-	130,012
Parent net investment attributable to non-controlling interests	-	719
Owners' equity:		
Partners’ capital:		
Common units (5,913,000 units outstanding at December 31, 2014)	6,285	-
Subordinated units (5,913,000 units outstanding at December 31, 2014)	66,096	-
General partner	1,999	4,816
Accumulated other comprehensive loss	(525)	-

Total partners' capital	73,855	4,816
Non-controlling interests	26,573	-
Total parent net investment and owners' equity	100,428	135,547
Total liabilities, parent net investment and owners' equity	$ 189,842	$ 240,590

See accompanying notes.

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CYPRESS ENERGY PARTNERS, L.P.
Consolidated Statements of Operations
For the Years Ended December 31, 2014 and 2013 and
the Period from March 15, 2012 (Inception) through December 31, 2012,
and for our Predecessor for the Year Ended December 31, 2012
(in thousands, except unit and per unit data)

	Cypress Energy Partners, L.P.			Predecessor
	2014	2013 Recast - Note 2	2012	2012
Revenues	$404,418	$249,133	$619	$ 12,203
Costs of services	355,355	213,690	309	3,662
Gross margin	49,063	35,443	310	8,541
Operating costs and expense:				
General and administrative	21,321	12,467	2,056	477
Depreciation, amortization and accretion	6,345	5,164	99	1,398
Impairments	32,546	4,131	-	-
Operating (loss) income	(11,149)	13,681	(1,845)	6,666
Other income (expense):				
Interest expense, net	(3,208)	(4,000)	-	(111)
Offering costs	(446)	(1,376)	-	-
Gain on reversal of contingent consideration	-	11,250	-	-
Other, net	92	37	-	40
Net (loss) income before income tax expense	(14,711)	19,592	(1,845)	6,595
Income tax expense	468	15,237	-	-
Net (loss) income	(15,179)	4,355	$(1,845)	$ 6,595
Net income attributable to non-controlling interests	4,973	22		
Net (loss) income attributable to partners / controlling interests	(20,152)	$4,333		
Net income attributable to general partner	149			
Net loss attributable to limited partners	$(20,301)			
Net loss attributable to limited partners allocated to:				
Common unitholders	$(10,150)			
Subordinated unitholders	(10,151)			
	$(20,301)			
Net loss per common limited partner unit – basic and diluted	$(1.72)			
Net loss per subordinated limited partner unit – basic and diluted	$(1.72)			
Weighted average common units outstanding - basic and diluted	5,913,000			
Weighted average subordinated units outstanding - basic and diluted	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 30, 2014 and 2013 and
the Period from March 15, 2012 through December 31, 2012,
and for our Predecessor for the Year Ended December 31, 2012
(in thousands)

	Cypress Energy Partners, L.P.			Predecessor
	2014	2013 Recast - Note 2	2012	2012
Net (loss) income	$(15,179)	$4,355	$(1,845)	$ 6,595
Other comprehensive income (loss) –foreign currency translation	(937)	(112)	-	-
Comprehensive (loss) income	$(16,116)	$4,243	$(1,845)	$ 6,595
Comprehensive income attributable to non-controlling interests	4,658	22	-	-
Comprehensive (loss) income attributable to partners/controlling interests	$(20,774)	$4,221	$(1,845)	$ 6,595

See accompanying notes.

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CYPRESS ENERGY PARTNERS, L.P.
Consolidated Statement of Owners' Equity
For the Years Ended December 31, 2014, 2013 and 2012
(in thousands, except unit data)

	Predecessor	Cypress Energy Partners, L.P.								
				Partners' Capital						
	Members' Equity	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 at December 31, 2011	$ 9,265	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital contributions	2	1	-	-	-	-	-	-	-
Net advances from (distributions to) members	8,907	(505)	-	-	-	-	-	-	-
Net income (loss)	6,595	(1,845)	-	-	-	-	-	-	-
Purchase of Predecessor entity	(24,769)	24,769	-	-	-	-	-	-	-
Member contributions in excess of Predecessor equity (Recast - Note 2)	-	44,077	-	-	-	-	-	-	-
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 distributions 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 (Recast - Note 2)	130,012	719	4,816	-	-	-	-	4,816
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 from January 1, 2014 to January 20, 2014	(304)	-	-	-	-	-	-	-
Net distributions to members	(168)	-	-	-	-	-	-	-
Contribution attributable to general partner		-	979	-	-	-	-	979
Contribution 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 offering costs	-	-	(2,853)	80,213	-	-	-	77,360
Distribution of initial public offering proceeds to Cypress Energy Holdings,	-	-	-	(80,213)	-	-	-	(80,213)

LLC								
Distributions to partners	-	-	-	(6,532)	(6,532)	-	-	(13,064)
Distributions to non-controlling interests	-	-	-	-	-	-	(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

See accompanying notes.

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CYPRESS ENERGY PARTNERS, L.P.
Consolidated Statements of Cash Flows
For the Years Ended December 31, 2014 and 2013 and
the Period from March 15, 2012 through December 31, 2012,
and for our Predecessor for the Year Ended December 31, 2012
(in thousands)

	Cypress Energy Partners, L.P.			Predecessor
	2014	2013 Recast - Note 2	2012 Recast - Note 2	2012
Operating activities:				
Net income (loss)	$(15,179)	$4,355	$(1,845)	$ 6,595
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:				
Depreciation, amortization and accretion	6,513	5,261	99	1,398
Impairments	32,546	4,131	-	-
Loss on asset disposal	3	-	-	-
Gain on reversal of contingent consideration	-	(11,250)	-	-
Interest expense from debt issuance cost amortization	714	1,219	-	-
Amortization of equity-based compensation	785	90	-	-
Equity earnings in investee company	(46)	(32)	-	-
Distributions from investee company	55	-	-	-
Deferred tax benefit, net	(13)	(2,016)	-	-
Non-cash allocated expenses	497	-	-	-
Changes in assets and liabilities:				
Trade accounts receivable	6,650	(8,793)	(741)	(219)
Prepaid expenses and other	(933)	283	(12)	(353)
Accounts payable and accrued payroll and other	(2,964)	(1,910)	255	(175)
Income taxes payable	(15,612)	15,816	-	-
Net cash provided by (used in) operating activities	13,016	7,154	(2,244)	7,246
Investing activities:				
Cash acquired (see Note 4)	-	10,108	-	-
Acquisitions of businesses	(1,769)	(500)	(65,555)	-
Purchases of property and equipment	(517)	(3,829)	(58)	(15,236)
Net cash provided by (used in) investing activities	(2,286)	5,779	(65,613)	(15,236)
Financing activities:				
Proceeds from initial public offering	80,213	-	-	-
Distribution of initial public offering proceeds (see Note 3)	(80,213)	-	-	-
Payment of offering costs	(314)	(2,539)	-	-
Proceeds from long-term debt	7,600	75,000	-	-
Repayment of long-term debt	(5,000)	(19,385)	-	(484)
Net payments on factoring agreement	-	(36,748)		
Payment of debt issuance costs	(883)	(3,368)	-	-
Payments on behalf of affiliates	-	(5,763)	(505)	-
Purchase of non-controlling interests	-	(572)	-	-
Tax benefit of stock options exercised	-	528	-	-
Net contributions from (distributions to) members prior to IPO	(168)	-	68,846	8,909

Contributions from general partner	482	6,210	-	-
Distributions to limited partners	(13,064)	-	-	-
Distributions to non-controlling members of the TIR Entities	(4,683)	-	-	-
Net cash provided by (used in) financing activities	(16,030)	13,363	68,341	8,425
Effect of exchange rates on cash	(633)	(90)	-	-
Net increase (decrease) in cash and cash equivalents	(5,933)	26,206	484	435
Cash and cash equivalents, beginning of period	26,690	484	-	147
Cash and cash equivalents, end of period	$20,757	$26,690	$484	$ 582
Non-cash items:				
Accounts payable excluded from capital expenditures	$756	$330	$145	$ 91
Supplemental cash flow disclosures:				
Cash taxes paid	$16,674	$817	$-	$ -
Cash interest paid	2,415	3,917	-	111

See accompanying notes.

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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 on September 19, 2013 to provide saltwater disposal (“SWD”) and other water and environmental services to U.S. onshore oil and natural gas producers and trucking companies and to provide independent pipeline inspection and integrity services to producers and pipeline companies. On January 21, 2014, we completed the initial public offering (“IPO”) of our common units representing limited partner interests. In connection with the IPO, Cypress Energy Holdings II, LLC (“Holdings II”), a wholly owned subsidiary of Cypress Energy Holdings, LLC (“Holdings”), conveyed a 100% interest in Cypress Energy Partners, LLC (“CEP LLC”), in exchange for (a) an aggregate 47.8% interest in the Partnership comprised of 671,250 common units and 4,983,750 subordinated units, and (b) the right to receive the proceeds of the IPO. Prior to its contribution to the Partnership, CEP LLC distributed to Holdings its interest in SBG Sheridan Facility, LLC, which owns and operates a SWD facility in Sheridan, Montana as well as its interest in three other non-operating subsidiaries. In addition, affiliates of Holdings, conveyed an aggregate 50.1% 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 in exchange for an aggregate 15.7% ownership in the Partnership comprised of 929,250 common units and 929,250 subordinated units. The Partnership subsequently conveyed its interest in the TIR Entities to CEP LLC. Together, CEP LLC and the TIR Entities are hereafter collectively referred to as the “Contributed Entities”. Affiliates of Holdings held the remaining 49.9% interest in the TIR Entities not contributed to the Partnership until February 1, 2015 when the Partnership acquired the remaining interest (see Note 17).

Our business is organized into the Water and Environmental Services (“W&ES”) and Pipeline Inspection and Integrity Services (“PI&IS”) reportable segments. All remaining business activities are included in Other. W&ES provides services to oil and natural gas producers and trucking companies and consists of the operations of CEP LLC. CEP LLC is a Delaware limited liability company, which was formed on March 15, 2012 (Inception) and acquired 100% of the outstanding units of seven North Dakota limited liability companies from SBG Energy Services, LLC (“SBG Energy”) on December 31, 2012. Since the acquisition of these companies, the president and chief executive officer of SBG Energy has served as a member of our board of directors. These seven companies collectively comprise our predecessor for accounting purposes (“Predecessor”). These Predecessor entities were formed in 2011 and 2012, with the first being formed on June 1, 2011. CEP LLC currently owns and operates eight commercial SWD facilities in the Bakken Shale region of the Williston Basin in North Dakota, as well as two in the Permian Basin in Texas. All of the facilities currently utilize specialized equipment, full-time attendants, 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 the SWD facilities, our consolidated 51% subsidiary, Cypress Energy Services, LLC (“CES LLC”), provides management and staffing services for three additional SWD facilities in the Bakken Shale region, pursuant to management agreements. CES LLC also owns a 25% member interest in one of the managed facilities. CES was acquired effective October 1, 2013.

PI&IS provides inspection and integrity services to various energy, public utility and pipeline companies in both the United States and Canada and consists of the operations of the TIR Entities. Our inspectors perform a variety of services on midstream pipelines, gathering systems and distribution systems, including data gathering and supervision of third-party construction, inspection, and maintenance and repair projects. Services are provided in Canada through two wholly owned subsidiaries of TIR Holdings – Tulsa Inspection Resources-Canada, ULC (“TIR-Canada”) and Foley Inspection Services, ULC (“TIR-Foley”) – both Canadian unlimited liability corporations.

Other includes other business activities that are not operating segments, as well as corporate operations.

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 the Contributed 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 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.

The information presented for our Predecessor for 2012 includes the activity of the four subsidiaries contributed to Holdings prior to the contribution of CEP LLC to the Partnership and does not reflect the fair value of the assets and liabilities recorded by the Partnership when the Predecessor was acquired by CEP LLC (see Note 4).

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 the 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 from 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.

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During 2014, Holdings incurred allocated overhead expenses on behalf of the Partnership totaling $0.5 million. 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 Statement of Operations for the year ended December 31, 2014 and as an equity contribution 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.

U.S. cash balances at December 31, 2014, 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, 2014 and 2013, we believe our credit risk related to these funds is minimal.

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Deferred Offering Costs

Incremental costs directly attributable to an offering of equity securities are deferred and charged against the gross proceeds of the offering as a reduction in owners' equity, including underwriter fees, legal and accounting fees associated with the preparation of the registration statement, and other costs related to the promotion of the offering. All other costs that are not directly related to the offering are expensed as incurred.

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.

Debt Issuance Costs

Debt issuance costs represent fees and expenses associated with securing the Partnership’s credit agreement (see Note 8). 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 has one subsidiary, Tulsa Inspection Resources – PUC, LLC (“TIR-PUC”), which has elected to be taxed as a corporation 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, our qualifying income met the statutory 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, 2014 or 2013. Any interest or penalties would be recognized as a component of income tax expense.

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CYPRESS ENERGY PARTNERS, L.P.
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 services are recognized when the services are provided and collectability is reasonably assured. Generally, inspection services and use of provided equipment are billed on a per day basis.

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 12.

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.

The Company had a net loss for the year ended December 31, 2014. As a result, all phantom restricted units were anti-dilutive and excluded from the weighted average units used in determining the loss per unit. There were 14,520 phantom restricted units that were excluded from the calculation of net income per unit as they were anti-dilutive.

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 $0.2 million at December 31, 2014 and 2013, and recorded bad debt expense of $0.1 million and $0.4 million for the years ended December 31, 2014 and 2013, respectively. There was no bad debt expense recorded during the year ended December 31, 2012.

We had 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.

Fair Value of Financial Instruments

The carrying amounts reported in the Consolidated Balance Sheets for cash and cash equivalents, trade accounts receivable, 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 and intangible assets 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 $12.8 and $3.4 million for the years ended December 31, 2014 and 2013, respectively (see Note 5).

Goodwill

At December 31, 2014 and 2013, the Partnership had $55.6 and $75.5 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, 2014 and 2013, W&ES and PI&IS, 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 PI&IS reporting unit, we performed a qualitative assessment to determine whether the fair value of the reporting unit was more likely than not less than its carrying value. 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 assessment on this reporting unit indicated that there was no need to conduct further quantitative testing for goodwill impairment nor did our analysis indicate the reporting unit was 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.

As a result of our valuation we determined that the carrying value of the W&ES reporting unit exceed 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 some of the regions in which we operate which has resulted in declining volumes and increased pricing pressure. The fourth quarter decline in oil prices has intensified competitive pressures and 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. Lower oil prices will also directly impact revenues as oil sales have historically represented in excess of 20% of our W&ES revenues.

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.

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We review our other 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 2014 and 2012. During 2013, the Partnership determined that one of its trade names in PI&IS 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.

Non-controlling Interest

The Partnership holds a controlling interest in several entities which are not wholly owned. The non-controlling interests shown in our Consolidated Balance Sheet at December 31, 2014 primarily includes the 49% membership interest in CES LLC that is owned by SBG Energy and the 49.9% interest in each of the TIR Entities that is owned by affiliates of Holdings. Net income attributable to non-controlling interests shown in our Consolidated Statements of Operations reflects 49% of the net income of CES LLC for the years ended December 31, 2014 and 2013, and 49.9% of the net income of the TIR Entities for the period from our IPO through December 31, 2014. The non-controlling interest in the TIR Entities is reduced by certain charges in accordance with our Partnership agreement.

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 new controlled assets meet the definition of a business, it is accounted for as a business combination; otherwise it is accounted for as an asset acquisition. Transactions discussed in Note 4 reflect 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 Standard

The Financial Accounting Standards Board issued Accounting Standards Update (“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. The Partnership will be required to comply with this ASU beginning in 2017. 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.

3. Initial Public Offering

On January 21, 2014, the Partnership completed its IPO consisting of 4,312,500 common units, representing limited partner interests in the Partnership at a price to the public of $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 Holdings II as reimbursement for certain capital expenditures it incurred with respect to assets contributed to us.

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.

4. Business Combinations

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 were as follows:

	Fair Value (in thousands)
Current assets	$ 50
Property and equipment	1,837
Intangible assets - contracts	241
Total value of assets acquired	2,128
Current liabilities assumed	386
Asset retirement obligation	1
Net assets acquired	$ 1,741

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

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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:

	Fair Value (in thousands)
Cash	$ 10,108
Other working capital, net	33,990
Property and equipment	1,075
Intangible assets:	
Trade names and trademarks	10,850
Inspector database	2,080
Customer relationships	21,380
Goodwill	40,638
Total value of assets acquired	120,121
Mezzanine debt	19,756
Factoring debt	36,748
Total liabilities assumed	56,504
Net assets acquired	$ 63,617

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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 the SBG Acquisition discussed below, the Partnership had previously assigned a fair value of $0.2 million to its option to purchase these assets. The exercise of the 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 are considered Level 3 fair value estimates. The purchase price and assessment of the fair value of the assets acquired and liabilities assumed for the SBG Disposal acquisition were as follows:

	Fair Value (in thousands)
Current assets	$ 35
Property and equipment	300
Intangible assets - customer relationships	150
Goodwill	971
Total assets acquired	1,456
Current liabilities	35
Net assets acquired	$ 1,421

The customer relationships are amortized over a five year period.

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2012 Business Combinations

Moxie Acquisition

In December 2012, the Partnership acquired four commercial SWD facilities through two agreements for a total purchase price of approximately $23.9 million, subject to customary adjustments. The acquisitions were funded with available cash from member equity contributions. The effective date of the acquisition was December 3, 2012, and the Partnership took over operations of the wells on December 4, 2012.

SBG Acquisition

In December 2012, the Partnership acquired 100% of the interests in six operating commercial SWD facilities, one under-construction commercial SWD facility, an option to acquire a 51% interest in certain assets of SBG Disposal, LLC for $0.5 million, including a 25% ownership interest in an LLC that owns and operates a SWD facility ("Purchase Option") and various other rights of first refusal to purchase other businesses and assets from SBG Energy. The Partnership assigned a fair value of $0.2 million to the Purchase Option which was exercised on October 1, 2013. The total purchase price was approximately $47.3 million, net of customary adjustments. One of these customary adjustments included the requirement of SBG Energy to include $8.2 million for a series of well improvement and construction reserves, which effectively reduced the purchase price. Any future capital obligations related to these well improvements or new SWD facility construction projects are the responsibility of the Partnership. The acquisition was funded with available cash from member equity contributions. The closing date of the acquisition was December 31, 2012.

The Moxie Acquisition and the SBG Acquisition qualified as business combinations and were accounted for under the acquisition method of accounting. The Partnership recorded the assets acquired and liabilities assumed at their estimated fair market values as of the closing dates. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

Fair value measurements also utilize the following primary assumptions of market participants. To estimate the fair value of the acquired SWD facilities, the Partnership used a discounted cash flow model and made market assumptions for the estimation of future water to be disposed of due to oil and gas drilling and production volumes in the markets served, risks associated with the different zones into which salt water is disposed, expected future disposal rates and commodity prices, capital expenditures, operating costs, and appropriate discount rates. Due to the unobservable nature of the inputs, these estimates of the fair value of the acquired wells are considered Level 3 fair value measurements.

The purchase price and assessment of the fair value of the assets acquired and liabilities assumed for the Moxie Acquisition and the SBG Acquisition, which included certain properties not contributed to the Partnership, were as follows:

	Moxie Acquisition	SBG Acquisition	Total
	(in thousands)		
Fair value of net assets:			
Current assets	$288	$ 2,947	$3,235
Property and equipment	16,634	30,017	46,651
Related-party notes receivable	—	438	438
Intangible assets	60	225	285
Goodwill	6,903	26,974	33,877
Total assets acquired	23,885	60,601	84,486
Current liabilities	—	500	500
Related-party notes payable	—	1,534	1,534
Contingent consideration due sellers	—	11,250	11,250
Asset retirement obligations	3	5	8
Total liabilities assumed	3	13,289	13,292
Total purchase price	$23,882	$ 47,312	$71,194

Contingent consideration was due to sellers based upon the acquired assets meeting certain profitability thresholds for 2013. Management's initial estimate was that the sellers would be due $11.25 million based upon achieving 50% of their maximum possible results by attaining $12.8 million in 2013 EBITDA (earnings before income taxes, depreciation, and amortization) on the acquired SWD facilities. Accordingly, the Partnership recorded a liability for the contingent consideration totaling $11.25 million. During the second quarter of 2013, management estimated that the financial results would be below the minimum threshold for the seller to earn any contingent consideration based on the actual performance of these wells for 2013 and the forecasted EBITDA for the remaining of the year.. The contingent liability was reversed in full during the second quarter 2013 and is recorded in the Consolidated Statements of Operations as a gain on reversal of contingent consideration. The EBITDA forecast is considered a Level 3 fair value measurement.

Intangible assets consist primarily of various 36-month non-compete agreements associated with the Moxie Acquisition to which the Partnership has assigned a fair value of $0.1 million, as well as the $0.2 million Purchase Option discussed above which was contributed to the SBG Disposal Acquisition. The non-compete agreements are being amortized ratably over three years.

Goodwill for the Moxie and SBG transactions represents the excess of cost over the fair value of identified assets, liabilities, and contingent liabilities. The Partnership believed the locations, synergies created by combining these entities, and the projected future cash flows of the acquired entities merit the recognition of this asset. The goodwill is fully deductible for tax purposes by our partners.

The following summarized pro forma information for the years ended December 31, 2014, 2013 and 2012 presents the combined results of the Partnership as if the business combinations occurred as of the later of January 1, 2012 or the initiation of operations of the acquired business:

	2014	2013	2012

	(in thousands)		
Revenue as reported	$404,418	$249,133	$619
Business Combinations:			
SWD Facility	297	-	-
TIR Entities Acquisition	-	152,989	233,803
SBG Disposal Acquisition	-	814	-
SBG Acquisition	-	-	8,588
Moxie Acquisition	-	-	3,180
Pro-forma revenue	$404,715	$402,936	$246,190
Net income (loss) as reported	$(15,179)	$4,355	$(1,845)
Business Combinations:			
SWD Facility	(213)	-	-
TIR Entities Acquisition	-	953	2,662
SBG Disposal Acquisition	-	127	-
SBG Acquisition	-	-	4,462
Moxie Acquisition	-	-	1,391
Pro-forma net income (loss)	$(15,392)	$5,435	$6,670

These pro forma results are for comparative purposes only and may not be indicative of the results that would have occurred had the acquisitions been completed on the later of January 1, 2012 or the commencement date of the acquired business, or the results that may be attained in the future.

5. Property and Equipment

Property and equipment consist of the following, recorded at cost, as of December 31, 2014 and 2013:

Asset Category	Useful Lives	December 31, 2014	2013
		(in thousands)	
Land		$2,049	$2,049
Land improvements	15 years	1,143	2,543
Buildings and leasehold improvements	39 years	1,056	1,767
Facilities, wells, and equipment	5 – 15 years	22,666	35,326
Computer and office equipment	3 – 9 years	816	771
Other	3 – 5 years	148	73
		27,878	42,529
Less accumulated depreciation		(3,538)	(3,711)
Net property and equipment		$24,340	$38,818

Depreciation expense is computed using the straight-line method over the estimated useful lives of the assets. Depreciation expense was $4.1 million, $4.1 million and $0.1 million for the Partnership for the years ended December 31, 2014, 2013 and 2012, respectively, of which $0.2 million and $0.1 million was included as a component of costs of services for the years ended December 31, 2014 and 2013. Depreciation expense for the Predecessor in 2012 was $1.2 million. Additionally, as a result of our impairment analysis, we wrote down the value of certain property and equipment which resulted in a decrease of accumulated depreciation of $4.3 million $0.6 million in 2014 and 2013, respectively.

During 2014, the Partnership recorded impairments of property and equipment at five of its SWD facilities. At each of these facilities, the Partnership experienced revenue and volume decreases due to lower commodity markets 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 estimate of undiscounted future cash flows from the facilities to the carrying amount of the long-lived assets of the facilities, and determined they were no longer recoverable and were impaired.

The Partnership wrote these facility's assets down from their net carrying value of $20.0 million to their estimated fair value of $7.2 million and recognized an impairment on the facilities totaling $12.8 million included in the impairments caption on the Consolidated Statement of Operations for the year ended December 31, 2014.

During 2013, the Partnership recorded impairments at one of its SWD facilities. The Partnership experienced declining revenues and operating losses at this SWD facility since acquiring the facility on December 31, 2012 due to increased competition in proximity to the facility. Given these impairment indicators, the Partnership compared its estimate of undiscounted future cash flows from the facility to the carrying amount of the long-lived assets of the facility, and determined that they were no longer recoverable and were impaired.

The Partnership wrote the facility assets down from their net carrying value of $4.5 million to their estimated fair value of $1.1 million and recognized an impairment of the facility totaling $3.4 included in the impairments caption on the Consolidated Statement of Operations for the year ended December 31, 2013.

The following table shows the impaired property and equipment by category:

	Year Ended December 31, 2014	Year Ended December 31, 2013
	(in thousands)	
Asset Category		
Land improvements	$1,514	$725
Buildings and leasehold improvements	748	135
Facilities, wells and equipment	14,796	2,964
	17,058	3,824
Accumulated depreciation	(4,285)	(397)
Impairment of facilities	$12,773	$3,427

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 repair of the facility and the market conditions, including the Partnership's ability to generate and maintain sufficient revenues to operate the facility profitably, our estimate of expected future cash flows may change in the near term resulting in the need to further adjust our determination of fair value.

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6. Goodwill

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

	W&ES	PI&IS	Total
	(in thousands)		
Balance - December 31, 2012	$33,877	$-	$33,877
Goodwill from business combinations	971	40,638	41,609
Foreign currency translation	-	(20)	(20)
Balance - December 31, 2013	34,848	40,618	75,466
Impairments	(19,773)	-	(19,773)
Foreign currency translation	-	(148)	(148)
Balance - December 31, 2014	$15,075	$40,470	$55,545

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, 2014 and 2013, W&ES and PI&IS, 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 PI&IS reporting unit, we performed a qualitative assessment to determine whether the fair value of the reporting unit was more likely than not less than its carrying value. 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 assessment on this reporting unit indicated that there was no need to conduct further quantitative testing for goodwill impairment nor did our analysis indicate the reporting unit was 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.

As a result of our valuation, 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 some of the regions in which we operate which has resulted in declining volumes and increased pricing pressure. The fourth quarter decline in oil prices has 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. Lower oil prices will also directly impact revenues as oil sales have historically represented in excess of 20% of our W&ES revenues.

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CYPRESS ENERGY PARTNERS, L.P.
Notes to Consolidated Financial Statements - Continued

7. Intangible Assets

Intangible assets consist of the following at December 31, 2014 and 2013:

	Useful Lives	December 31, 2014 Gross Carrying Amount	December 31, 2014 Accumulated Amortization	December 31, 2013 Gross Carrying Amount	December 31, 2013 Accumulated Amortization
		(in thousands)			
Customer relationships	5-20 years	$21,510	$ 1,788	$21,510	$ 554
Contracts	3 years	241	-	-	-
Non-compete agreements	3 years	60	41	60	21
Trademarks and trade names	10 years	10,135	1,638	10,135	553
Inspector database	10 years	2,080	314	2,080	106
Total		$34,026	$ 3,781	$33,785	$ 1,234

Amortization expense for the years ended December 31, 2014 and 2013 was $2.4 million and $1.3 million respectively. There was no amortization expense for the year ended December 31, 2012.

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

Year Ending December 31,	(in thousands)
2015	$ 2,468
2016	2,391
2017	2,391
2018	2,305
2019	2,281
Thereafter	18,409
	$ 30,245

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

8. Credit Agreement

On December 24, 2013, the Partnership and our affiliate, Cypress Energy Partners – TIR, LLC ("CEP-TIR"), (together, the "Borrowers"), entered into a $120.0 million secured credit agreement (the "Credit Agreement") as co-borrowers and co-guarantors with a syndicate of banks that consists of a $65.0 million senior secured working capital revolving credit facility and a $55.0 million senior secured acquisition revolving credit facility. 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 and extended the maturity date to December 24, 2018. Availability under the acquisition revolving credit facility was increased to $125.0 million and availability under the working capital revolving credit facility was increased to $75.0 million. In addition, the amendment provides for an accordion feature that allows us to increase availability under the facilities by an additional $125.0 million.

At December 31, 2014 and 2013, there were outstanding borrowings under the credit agreement of $77.6 million and $75.0 million, respectively reflected on the Consolidated Balance Sheets as long-term debt. Borrowings under the credit agreement are due at maturity. If, at any time, outstanding borrowings exceed the combined borrowing base of the Borrowers, principal in the amount of the excess is due upon submission of the borrowing base calculation. Certain conditions defined in the Credit Agreement limit our access to the acquisition revolving credit facility to $89.7 million of the total $97.4 million available and $15.3 million of the total available $25.0 million under the working capital revolving credit facility at December 31, 2014. Certain circumstances, such as additional acquisitions, could offset the defined limitations and provide the Partnership the opportunity to fully access the stated borrowing limitations on the Credit Agreement. The obligations under our Credit Agreement are secured by a first priority lien on substantially all assets of the Borrowers.

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 combined leverage ratio of the Borrowers, as defined in the Credit Agreement. At December 31, 2014 and 2013, the interest rate in effect on outstanding LIBOR Borrowings was 3.03% and 3.14%, respectively, calculated as the weighted average LIBOR rate of 0.255% in 2014 and 0.225% in 2013 plus a weighted average margin of 2.77% in 2014 and 2.92% in 2013. There were no Base Rate Borrowings outstanding at December 31, 2014 or 2013. 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 payable quarterly.

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, 2014, our total adjusted leverage ratio was 0.94 to 1.0 and our interest coverage ratio was 9.14 to 1.0. 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 or our financial debt covenants throughout 2015.

In addition, our Credit Agreement restricts our ability to make distributions on, or redeem or repurchase our equity interests, provided, however, that 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 working capital revolving credit facility by at least $5.0 million and at least $5.0 million in lender commitments are available to be drawn under the borrowing base revolving credit facility. The combined calculated borrowing base of the Borrowers was $65.3 million at December 31, 2014 which represents our maximum availability under the working capital revolving credit facility as of that date. Availability under the acquisition revolving credit facility is not subject to a borrowing base calculation but is restricted by our maximum leverage calculation. Borrowings under the Credit Agreement are due at maturity. If at any time outstanding borrowings under the working capital facility exceed the combined borrowing base of the Borrowers, principal in the amount of the excess is due upon submission of the borrowing base calculation.

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

	December 31, 2013	Net borrowings or repayments	December 31, 2014
	(in thousands)		
Acquisition revolving credit facility (3.26% at December 31, 2014)	$25,000	$ 2,600	$ 27,600
Borrowing base revolving credit facility (2.74% at December 31, 2014)	50,000	-	50,000
Total long-term debt	$75,000	$ 2,600	$ 77,600

9. 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, effective January 1, 2014, we formed a wholly owned subsidiary, Tulsa Inspection Resources – PUC, LLC ("TIR-PUC"), which has elected to be taxed as a corporation 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. We are also subject to certain margin based taxes in some states.

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 and income taxes payable on the Consolidated Balance Sheet as of 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:

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

There was no income tax expense recorded for the year ended December 31, 2012.

The deferred tax assets and liabilities of the Partnership consisted of the following:

	Year Ended December 31,	
	2014	2013
	(in thousands)	
Current deferred tax assets:		
Accrued liabilities	$17	$1
Bad debt reserve	-	28
Canadian net operating loss	51	105
Total	$68	$134
Non-current deferred tax assets (liabilities):		
Property and equipment	$2	$3
Intangible assets	(440)	(544)
Total	$(438)	$(541)

The Canadian net operating loss expires in 2025 and as such, the Partnership has made no valuation allowance against this deferred tax asset as of December 31, 2014 or 2013.

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:

	2014	2013	2012	Predecessor 2012
		(in thousands)		

Tax (benefit) computed at statutory rate of 35%	$(5,149)	$6,857	$(646)	$ 2,170
Income not subject to federal taxes	5,274	(4,793)	646	(2,170)
State income taxes, net of federal benefit	326	535	-	-
Tax on conversion of TIR, Inc. to pass through entities	-	12,892	-	-
Other	17	(254)	-	-
Total income tax expense	$468	$15,237	$-	$ -

Tax years that remain subject to examination by various taxing authorities for each of our consolidated entities include the years 2011 through 2013.

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Notes to Consolidated Financial Statements - Continued

10. 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 equity in the Consolidated Balance Sheet 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, 2013 and 2012 were \$0.2 million, \$3.5 million and \$0.5 million, respectively.

Common Units and Subordinated Units

As of December 31, 2014, there are 5,913,000 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 year ended December 31, 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 2014.

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Notes to Consolidated Financial Statements - Continued

11. Major Customers

For the year ended December 31, 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 PI&IS segment.

12. 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. Holdings reimburses the Partnership for the direct expense of the awards and allocates the expense to us through the annual administrative fee provided for under the terms of our amended and restated omnibus agreement (Note 13). For the year ended December 31, 2014, compensation expense of $0.5 million was recorded under the LTIP. The following table sets forth the grants and forfeitures of Units under the LTIP for the year ended December 31, 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	17.36

Outstanding Units issued to directors vest ratably over a three-year period from the date of grant. Units granted to employees vest over a five-year period from the date of grant, with one third vesting at the end of the third year, one third at the end of the fourth year and one third vesting at the end of the fifth year or will vest in full upon the occurrence of a Fundamental Change, as defined in the LTIP agreement. Total unearned compensation associated with the LTIP at December 31, 2014 was $2.1 million with an average remaining life of 3.9 years.

In conjunction with the IPO, phantom profits interest units previously issued under a CEP LLC LTIP were exchanged for 44,250 Units under the LTIP. Vesting under all of the exchanged awards is retroactive to the initial grant date. The awards will be considered for all purposes to have been granted under the Partnership's LTIP. In addition, at IPO, certain profits interest units previously issued under CEP LLC's LTIP 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 $0.3 million for the year ended December 31, 2014. 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 are accounted for as equity. The unearned compensation related to the subordinated units was $0.5 million with an average remaining life of 3.1 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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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 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
Granted	-	-
Exercised	(5)	(1,750)
Forfeited or expired	(2)	(700)
Outstanding at December 31, 2013	-	$ -

13. 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, which was amended and restated in February 2015 to reflect the acquisition of the remaining interests in the TIR Entities, governs the following matters, among other things:

- our payment of an annual administrative fee, initially in the amount of $4.0 million 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 compensation expense (including equity-based compensation) for all employees required to manage and operate our business. This fee also includes the incremental general and administrative expenses we incur as a result of being a publicly traded partnership;

- limitations on the amount of indebtedness CEP-TIR may incur under our credit agreement and the allocation of certain interest expenses to the TIR Entities;

- 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 pipeline inspection and integrity services; and

- indemnification of us by Holdings for certain environmental and other 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, our amended and restated 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 our amended and restated 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 our amended and restated 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 year ended December 31, 2014 was $3.8 million and is reflected in general and administrative in the Consolidated Statements of Operations.
Additional expenses were incurred by Holdings in support of the Partnership totaling $0.5 million. These expenses were also allocated to the Partnership and are reflected in general and administration and as an equity contribution.

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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 interest in several entities with which the Partnership does business including the following:

- 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.

- Rud Transportation, LLC (“Rud”) – Rud, a wholly owned subsidiary of SBG Energy is a trucking company customer of the Partnership that hauls produced and flowback water to our facilities. Total revenue recognized by the Partnership from Rud was $2.1 million, $1.8 million and $0.7 million for the years ended December 31, 2014, 2013 and 2012 (Predecessor), respectively. Accounts receivable from Rud was $0.3 million and $0.4 million at December 31, 2014 and 2013, respectively, and is included in trade accounts receivable, net on the Consolidated Balance Sheets.

Effective October 1, 2013, the Partnership provides management services to its 25% owned investee company, Alati Arnegard, LLC (“Arnegard”). Management fee revenue earned from Arnegard totaled $0.6 million and $0.2 million for the years ended December 31, 2014 and 2013, respectively. Accounts receivable from Arnegard totaled $0.1 million at December 31, 2014 and 2013 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”). Total employee related costs paid to CEM-BO were $3.2 million and $0.8 million for the years ended December 31, 2014 and 2013, respectively. Included in accounts payable on the Consolidated Balance Sheets was $0.2 million and $0.1 million at December 31, 2014 and 2013, respectively, related to this arrangement.

During 2013, PI&IS had business activity with Contract Pro, a nonaffiliated Canadian company owned by two former 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.

14. Commitments and Contingencies

Security Deposits

The Partnership has various performance obligations which are secured with short-term security deposits of $0.5 million and $0.4 million at December 31, 2014 and 2013, respectively. These amounts are included in prepaid expenses and other on the Consolidated Balance Sheets.

Employment Contract Commitments

A subsidiary of the Partnership has employment agreements with certain of its executives. The executive employment agreements are effective for a term of two-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. As of December 31, 2014, the aggregate commitment for future compensation and severance was approximately $0.9 million.

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 December 30, 2014 and 2013, the Partnership had contingent liabilities of $0.2 million and $0.4 million respectively, associated with the probable settlement related to ongoing customer audits of various charges previously approved by customer representatives reflected in accrued payroll and other on the Consolidated Balance Sheets. While the audits are ongoing, any contingent amounts that are still under evaluation will not be recorded as contingent liabilities until they are determined to be inconsistent with the MSA.

Legal Proceedings

On July 3, 2014, a group of former minority shareholders of 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. 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.

On February 2, 2015, a former inspector for TIR LLC filed a putative collective action lawsuit alleging that TIR LLC failed to pay a class of workers overtime in compliance with the Fair Labor Standards Act (“FLSA”) titled Fenley v. TIR LLC in the United States District Court for the District of Kansas. The plaintiff alleges he was a non-exempt employee of TIR and that he and other potential class members were not paid overtime in compliance with the FLSA. The plaintiff seeks to proceed as a collective action and to receive unpaid overtime and other monetary damages, including attorney’s fees. We believe that the possibility of the Partnership incurring material losses as a result of this action is remote. In addition, we do not anticipate any disruption in our business operations related to this action.

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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 $0.1 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, 2014 follows:

	(in thousands)
2015	$ 561
2016	478
2017	389
2018	134
2019	25
Thereafter	557
Total	$ 2,144

15. Segment Disclosures

The Partnership's operations consist of two reportable segments. We have recast segment financial information to reflect the conveyance of the entities comprising our reportable segments to the Partnership at the closing of our IPO (see Note 3). Our reportable segments consist of the following.

W&ES – This segment consists of ten SWD facilities. We aggregate these facilities for reporting purposes as they have similar economic characteristics and have centralized management and processing. This segment generates revenue primarily by treating produced water and flowback water and injecting it into our SWD facilities. Segment results are driven primarily by the volumes of water we inject into the 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 recovered from the disposal process.

PI&IS – This segment consists of the operations of the TIR Entities. We aggregate these operating entities for reporting purposes as they have similar economic characteristics, as well as possessing 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 and integrity 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. The financial results of this segment have been included since June 26, 2013, the date Holdings and its affiliates acquired a controlling interest in the TIR Entities.

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

	W&ES	PI&IS	Other	Total
	(in thousands)			
Year ended December 31, 2014				
Revenue	$22,416	$382,002	$-	$404,418
Costs of services	8,617	346,738	-	355,355
Gross margin	13,799	35,264	-	49,063
General and administrative expense	3,090	17,734	497	21,321
Impairments	32,546	-	-	32,546
Depreciation, amortization and accretion	3,806	2,539	-	6,345
Operating (loss) income	$(25,643)	$14,991	$(497)	(11,149)
Interest expense, net				3,208
Offering costs				446
Other expense, net				(92)
Net loss before income tax expense				$(14,711)
Total Assets	$50,296	$136,224	$3,322	
Year ended December 31, 2013				
Revenue	$22,232	$226,901	$-	$249,133
Costs of services	7,347	206,343	-	213,690
Gross margin	14,885	20,558	-	35,443
General and administrative expense	3,292	9,175	-	12,467
Impairments	3,429	702	-	4,131
Depreciation, amortization and accretion	3,837	1,327	-	5,164
Operating income	$4,327	$9,354	$-	13,681
Interest expense, net				4,000
Offering costs				1,376
Gain on reversal of contingent consideration				(11,250)
Other expense, net				(37)
Net income before income tax expense				$19,592
Total Assets	$81,403	$154,352	$4,835	
Year ended December 31, 2012				
Revenue	$619	$-	$-	$619
Costs of services	309	-	-	309
Gross margin	310	-	-	310
General and administrative expense	(4)	-	2,060	2,056
Depreciation, amortization and accretion	99	-	-	99
Operating income (loss)	$215	$-	$(2,060)	$(1,845)
Total Assets	$79,990	$-	$-	

Year ended December 31, 2012 (Predecessor)				
Revenue	$12,203	$-	$-	$12,203
Costs of services	3,662	-	-	3,662
Gross margin	8,541	-	-	8,541
General and administrative expense	477	-	-	477
Depreciation, amortization and accretion	1,398	-	-	1,398
Operating income	$6,666	$-	$-	6,666
Interest expense, net				111
Other expense, net				(40)
Net income before income tax expense				$6,595

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Notes to Consolidated Financial Statements – Continued

16. Distributions

We paid the following distributions related to the year ended December 31, 2014 (in thousands, except per unit amount):

Payment Date	Per Unit Cash Distribution	Total Cash Distribution
May 15, 2014 (a)	$ 0.301389	$ 3,565
August 14, 2014	0.396844	4,693
November 14, 2014	0.406413	4,806
	1.104646	13,064
February 14, 2015 (b)	0.406413	4,806
	$ 1.511059	$ 17,870

(a) Distribution was pro-rated from the date of our IPO through March 31, 2015.
(b) Fourth quarter 2014 distribution was declared and paid in 2015.

17. Subsequent Events

Additional Interest in the TIR Entities

Subsequent to year-end effective February 1, 2015, the Partnership acquired the remaining 49.9% interest in the TIR Entities for $52.6 million financed through the Partnership's acquisition revolving credit facility of the Credit Agreement and now owns 100% of the TIR Entities as of that date. Since the Partnership already controlled and consolidated the TIR Entities, the entire $52.6 million will be recorded directly to owners' equity. No pro forma results of operations have been provided due to the fact that the Partnership has already consolidated the results of the TIR Entities, therefore the results of operations are already included in its Consolidated Financial Statements.

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CYPRESS ENERGY PARTNERS, L.P.
Quarterly Financial Information
(Unaudited)

The following table sets forth certain unaudited financial data for each quarter during 2014 and 2013. The unaudited quarterly information includes all normal recurring adjustments that we consider necessary for a fair presentation of the information shown.

2014	Quarter Ended, (in thousands, except per unit amounts)			
	March 31,	June 30,	September 30,	December 31,
Revenues	$97,523	$93,722	$111,016	$102,157
Gross margin	11,420	12,303	13,281	12,059
Impairments	-	-	-	32,546
Net income (loss)	3,517	4,929	5,097	(28,722)
Net income (loss) attributable to partners	2,744	3,680	3,555	(30,131)
Net income (loss) per common limited partner unit – basic	0.18	0.31	0.30	(2.51)
Net income (loss) per common limited partner unit – diluted	0.17	0.31	0.30	(2.51)
Net income (loss) per subordinated limited partner unit –basic and diluted	0.18	0.31	0.30	(2.51)

2013	Quarter Ended, (in thousands)			
	March 31,	June 30,	September 30,	December 31,
Revenues	$5,337	$9,176	$116,980	$117,640
Gross margin	3,755	3,725	14,311	13,652
Impairments	-	-	-	4,131
Gain on reversal of contingent consideration	-	11,250	-	-
Income tax expense	-	53	1,211	13,973
Net income	2,231	12,824	4,488	(15,188)
Net income attributable to controlling interests	2,231	12,824	4,488	(15,210)

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures.

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including the principal executive officer and principal financial officer of our general partner, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or Rule 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including the principal executive officer and principal financial officer of our general partner, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, the principal executive officer and principal financial officer of our general partner have concluded that our disclosure controls and procedures were effective at the reasonable assurance level as of December 31, 2014. Additionally, we have implemented a quarterly sub-certification process whereby all members of upper management and certain other management will review our filings and confirm their responsibility for, among other things, the effectiveness of key controls in their functional areas and that they are unaware of inaccuracies or omissions in our financial statements.

Our management, including our principal executive officer and principal financial officer, does not expect that our disclosure controls or our internal controls over financial reporting (“Internal Controls”) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Partnership have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that simple errors or mistakes can occur. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based, in part, upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our disclosure controls and internal controls and make modifications as necessary; our intent in this regard is that the disclosure controls and the internal controls will be maintained as systems change and conditions warrant.

Management’s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate and effective internal control over financial reporting, as such term is defined under Exchange Act Rule 13a-15(f). Our internal control over financial reporting is a process that is designed under the supervision of our Chief Executive Officer and Chief Financial Officer, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Our internal control over financial reporting includes those policies and procedures that:

i. Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

ii. Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures recorded by us are being made only in accordance with authorizations of our management and Board of Directors; and

iii. Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

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

The internal controls are supported by written processes and complemented by a staff of competent business process owners, as well as competent and qualified external resources used to assist in testing the operating effectiveness of the internal control over financial reporting.

Management has conducted its evaluation of the effectiveness of internal control over financial reporting as of December 31, 2014, based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). Management's assessment included an evaluation of the design of our internal control over financial reporting and testing the operational effectiveness of our internal control over financial reporting. Management reviewed the results of the assessment with the Audit Committee of the Board of Directors. Based on its assessment and review with the Audit Committee, management concluded that, at December 31, 2014, we maintained effective internal control over financial reporting, and management believes that we have no material internal control weaknesses in our financial reporting process.

Attestation Report of the Registered Public Accounting Firm

Pursuant to the Jumpstart Our Business (“JOBS”) Act enacted in 2012, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002 for up to five years or through such earlier date that we are no longer an “emerging growth company” as defined in the JOBS Act.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

MANAGEMENT

Management of Cypress Energy Partners, L.P.

We are managed by the executive officers of CEM LLC, which is owned by our general partner and certain of its affiliates. Our general partner is not elected by our unitholders and will not be subject to re-election by our unitholders in the future. Holdings indirectly owns all of the membership interests in our general partner. Our general partner has a board of directors, and our unitholders are not entitled to elect the directors or directly or indirectly to participate in our management or operations. Our general partner will be liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Whenever possible, we intend to incur indebtedness that is nonrecourse to our general partner.

Our general partner has six directors. Holdings will appoint all members to the board of directors of our general partner. Pursuant to our general partner's operating agreement, Holdings appointed to our board of directors (i) Peter C. Boylan III, who has the right to serve as a director as long as CEP Capital Partners, LLC, an entity controlled by Mr. Boylan, is a member of Holdings and (ii) such other individuals selected by Mr. Boylan that, together with Mr. Boylan, constitute a percentage of the board of directors equal to the percentage of Holdings that CEP Capital Partners, LLC owns. In his exercise of this right, Mr. Boylan has appointed himself and may appoint others to the board. We have three independent directors who qualify for service on the audit committee. Our board of directors has determined that Henry Cornell, John T. McNabb II, and Stan Lybarger are independent under the independence standards of the NYSE and eligible for service on the audit committee. Despite the fact that Mr. Cornell beneficially owns 2.0% of Holdings, which together with its controlled affiliates owns approximately 58.8% of our outstanding limited partner interests, the board of directors determined he is independent in that he does not have a current relationship with us that would interfere with the exercise of his independent judgment in carrying out his responsibilities as a director.

Our general partner has the sole responsibility 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, but we sometimes refer to these individuals in this report as our employees. Employees of the TIR Entities were transferred to an affiliate of our general partner subsequent to the closing of our IPO.

Director Independence

Although most companies listed on the NYSE are required to have a majority of independent directors serving on the board of directors of the listed company, the NYSE does not require a publicly traded limited partnership like us to have a majority of independent directors on the board of directors of our general partner or to establish a compensation or a nominating and corporate governance committee. We are, however, required to have an audit committee of at least three members within one year of the date our common units are first listed on the NYSE, and all of our audit committee members are required to meet the independence and financial literacy tests established by the NYSE and the Exchange Act.

Committees of the Board of Directors

The board of directors of our general partner has an audit committee and a conflicts committee, and may have such other committees as the board of directors shall determine from time to time. Each of the standing committees of the board of directors will have the composition and responsibilities described below.

Audit Committee

Our general partner has an audit committee comprised of three directors who each meet the independence and experience standards established by the NYSE and the Exchange Act. Henry Cornell, John T. McNabb II, and Stan Lybarger serve as members of our audit committee. Mr. Lybarger began serving as Chairman of the audit committee upon his appointment on March 5, 2014. Mr. McNabb served as Chairman prior to that date. Our board of directors has determined that Mr. Lybarger and Mr. McNabb each have such accounting or related financial management expertise sufficient to qualify as an audit committee financial expert in accordance with Item 407(d) of Regulation S-K. Our audit committee will assist the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. Our audit committee will have the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof, and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. Our audit committee will also be responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm will be given unrestricted access to our audit committee.

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Conflicts Committee

At least two members of the board of directors of our general partner will serve on our conflicts committee to review specific matters that may involve conflicts of interest in accordance with the terms of our partnership agreement. John T. McNabb II and Stan Lybarger serve as the members of the conflicts committee. Mr. McNabb serves as the Chairman of the conflicts committee. The board of directors of our general partner will determine whether to refer a matter to the conflicts committee on a case-by-case basis. The members of our conflicts committee may not be officers or employees of our general partner or directors, officers, or employees of its affiliates, and must meet the independence and experience standards established by the NYSE and the Exchange Act to serve on a committee of a board of directors. In addition, the members of our conflicts committee may not own any interest in our general partner or any interest in us or our subsidiaries other than common units or awards under our incentive compensation plan. If our general partner seeks approval from the conflicts committee, then it will be presumed that, in making its decision, the conflicts committee acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Please read "Conflicts of Interest and Duties."

Directors and Executive Officers of Cypress Energy Partners GP, LLC

Directors are elected by Holdings and hold office until their successors have been elected or qualified or until their earlier death, resignation, removal or disqualification. Executive officers are appointed by, and serve at the discretion of, the board of directors. The following table shows information for the directors and executive officers of our general partner.

Name	Age	Position with Cypress Energy Partners GP, LLC
Peter C. Boylan III	51	Chairman of the Board, President and Chief Executive Officer
G. Les Austin	49	Vice President and Chief Financial Officer
Richard M. Carson	48	Vice President and General Counsel
Jeff English	40	Vice President of Operations
Don LaBass	47	Vice President, Controller and Chief Accounting Officer
Tony Ceci	33	Vice President of Corporate Development
Henry Cornell	58	Director
Phil Gisi	54	Director
Stan Lybarger	65	Director & Audit Committee Chairman
John T. McNabb II	70	Director & Conflicts Committee Chairman
Charles C. Stephenson, Jr.	78	Director

Peter C. Boylan III is co-founder, President and Chief Executive Officer of Holdings and Chairman of the Board, President and Chief Executive Officer of Cypress Energy Partners GP, LLC, having served in that capacity since September 2013. Since March 2002, Mr. Boylan has been the Chief Executive Officer of Boylan Partners, LLC, a provider of investment and advisory services. From 1995 to 2004, Mr. Boylan served in a variety of senior executive management positions of various public and private companies controlled by Liberty Media Corporation, including serving as a board member, Chairman, President, Chief Executive Officer, Chief Operating Officer and Chief Financial Officer of several different companies. Mr. Boylan currently serves on the board of directors of publicly traded BOK Financial Corporation, a multi-billion dollar regional financial services and bank holding company, and MRC Global Inc., a global industrial supplier of upstream, midstream and downstream sectors of the energy industry. Mr. Boylan has also served on a number of other public and private company boards of directors over the last 20 years.

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Mr. Boylan has extensive corporate senior executive management and leadership experience, and specific expertise with accounting, finance, audit, risk and compensation committee service, intellectual property, corporate development, health care, media, cable and satellite TV, software development, technology, energy and civic and community service. We believe this experience suits Mr. Boylan to serve as Chairman of the Board and Chief Executive Officer.

G. Les Austin is Vice President and Chief Financial Officer of Cypress Energy Partners GP, LLC, having served in that capacity since September 2013. Mr. Austin has served as Vice President and Chief Financial Officer of CEP LLC since October 1, 2012. Mr. Austin served as Senior Vice President, Chief Financial Officer, secretary and treasurer of RAM Energy Resources, Inc. from April 2008 until its sale in February 2012. Mr. Austin served as Vice President Finance and Chief Financial Officer of Matrix Service Company from June 2004 to March 2008. Mr. Austin also served Matrix as Vice President, Accounting and Administration, Vice President of Financial Reporting and Technology, and as Vice President of Financial Planning and Reporting. Mr. Austin served as Vice President of Finance for Flint Energy Construction Company from February 1994 to March 1999. Prior to February 1994, Mr. Austin was an audit manager with Ernst & Young LLP. Mr. Austin received a B.S. in Accounting and Information Technology from Oklahoma State University. He is a Certified Public Accountant and a member of the American Institute of Certified Public Accountants. In addition, Mr. Austin serves as a director on the Advisory Board of Oklahoma State University School of Accounting.

Richard M. Carson is Vice President and General Counsel, having served in that capacity since September 2013. Mr. Carson previously served as a director, officer and shareholder of Gable & Gotwals, an Oklahoma law firm, where he practiced securities, corporate finance, transactional and environmental law, primarily for clients in the energy industry, including several master limited partnerships. Prior to joining Gable & Gotwals, from 1999 to 2008, Mr. Carson served in the legal department of The Williams Companies, Inc., where he counseled Williams in regard to securities, corporate finance and environmental matters, particularly relating to Williams' master limited partnership subsidiaries, Williams Partners L.P., Williams Pipeline Partners L.P., and Williams Energy Partners L.P. (predecessor to Magellan Midstream Partners, L.P.). Mr. Carson began his career in 1991 working in legal, compliance and management roles, primarily in the environmental services industry, before joining Williams. Mr. Carson received a Juris Doctor in 1991 from the University of Oklahoma and a Bachelor of Science from the University of Tulsa's Honors Program in 1988. Mr. Carson serves on the board of directors of Land Legacy, a nonprofit land conservation organization, and he previously served as the Chair of the Oklahoma Bar Association's Environmental Law Section and the Environmental Auditing Roundtable's South-Central Region.

Jeff English is Vice President of Operations of Cypress Energy Partners GP, LLC, having served in that capacity since September 2013. Mr. English has served as Vice President Operations of CEP LLC since February 25, 2013. From 2011 to 2013, Mr. English was Vice President of Operations for Bosque Systems, LLC, a water management company with annual revenues of approximately $45 million in 2012, where he managed operations (including health, safety and environmental, construction, and compliance) in five regions and three business lines. From 2001 to 2011, Mr. English served as a senior director of operations for Vartec Telecom, a telecom company with annual revenues of $200 million. Prior to that, Mr. English was a senior consultant at Ernst & Young specializing in change management and business process improvement for complex customer relationship management system implementation. Mr. English is a graduate of Baylor University, with a M.A., Business Communication from Southwestern University.

Don LaBass is Vice President, Controller and Chief Accounting Officer of Cypress Energy Partners GP, LLC, having served in that capacity since September 2013. Mr. LaBass has served as VP Controller and Chief Accounting Officer of CEP LLC since July 2013. Mr. LaBass previously served as Senior Vice President and Chief Financial Officer for Cherokee Nation Businesses, or CNB, a diversified tribal holding company whose operations included gaming, manufacturing and professional services. Prior to joining CNB, from 1998 to 2005, Mr. LaBass served in senior financial positions with BOK Financial Corporation as well as Gemstar TV Guide International, Inc. and its Predecessors from 2005 until 2013. Mr. LaBass began his career in 1990 in public accounting with KPMG. Mr.

LaBass received a B.B.A. in Accounting from the University of Oklahoma. He is a Certified Public Accountant and a member of the American Institute of Certified Public Accountants. In addition, Mr. LaBass serves on the board of directors of the Eastern Oklahoma Chapter of the American Red Cross.

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Tony Ceci is Vice President of Corporate Development of Cypress Energy Partners GP, LLC, having served in that capacity since July 2014. Prior to joining, Mr. Ceci worked in the Energy Investment Banking Group at Raymond James & Associates, where he focused on public capital raises and M&A advisory work within the energy industry. Prior to joining Raymond James, Mr. Ceci spent eight years at General Electric (GE), where he held various assignments in corporate finance, including roles in financial planning and analysis, commercial finance, manufacturing finance and acquisition integration. He is a graduate of GE's Financial Management Program and served on GE's Corporate Audit Staff, where he conducted financial and operational audits in the United States, Europe and Asia. Mr. Ceci received an M.B.A., with honors, from The University of Texas at Austin and holds a B.A. with distinction in Economics from Connecticut College.

Henry Cornell has served as a director on the board of Cypress Energy Partners GP, LLC since January 14, 2014. Mr. Cornell was formerly a vice-chairman of the merchant banking division of Goldman Sachs & Co., where he worked for nearly 30 years prior to his retirement in February 2013. Mr. Cornell served on the firm's corporate, real estate and infrastructure investment committees. He also led Goldman Sachs & Co.'s investment activities in Asia from 1988 - 2000. Prior to joining Goldman Sachs & Co., Mr. Cornell worked at Davis Polk & Wardwell. He currently serves on the board of directors of MRC Global Inc., and is on the international advisory board of Sotheby's. Mr. Cornell is also the chairman of the board of the Citizens Committee for New York City, a trustee of the Asia Society, a trustee of the Whitney Museum, and a member of the Council on Foreign Relations. Mr. Cornell received his B.A. from Grinnell College in 1976 and his J.D. from New York Law School in 1981.

Mr. Cornell's experience as a vice-chairman of the merchant banking division of Goldman Sachs & Co. and his extensive management experience as a senior partner at Goldman Sachs & Co. qualifies him to serve on our board of directors. We believe Mr. Cornell's significant prior and current service as a director of public and private companies will suit him to serve as a director.

Phil Gisi has served as a director on the board of Cypress Energy Partners GP, LLC since January 14, 2014. Mr. Gisi has served as a director of CEP LLC since the acquisition of assets from SBG Energy Services, LLC on December 31, 2012. Mr. Gisi is primarily involved in the senior housing and assisted living business and is the owner, President and Chief Executive Officer of Edgewood Group LLC and Edgewood Vista Senior Living, Inc., Grand Forks, North Dakota. These companies develop, own and manage assisted living and memory care communities, employing over 1,800 people in seven states with a capacity of about 2,500 residents in 44 locations. Mr. Gisi was also co-founder, President and Chief Executive Officer of SBG Energy Services, LLC, which provides fluid transportation, water disposal and other services to the oil field industry in western North Dakota. Mr. Gisi currently serves as a board member of Altru Health System in Grand Forks, University of North Dakota, or UND, Alumni Association and UND Foundation, and is a Member of the Alumni Advisory Council of the College of Business and Public Administration at UND.

Mr. Gisi's service as President and Chief Executive Officer of Edgewood, and his extensive experience leading management teams enables him to serve on our board of directors. We believe Mr. Gisi's significant prior and current service in the water and environmental industry, including his prior service on CEP LLC's board, will suit him to serve as director.

Stan Lybarger has served as a director on the board of Cypress Energy Partners GP, LLC since March 5, 2014. Mr. Lybarger retired as president and chief executive officer of BOK Financial, a top 25 US-based bank holding company, on January 1, 2014. He continues to serve on the board of directors of that corporation. Mr. Lybarger had a 40-year career with BOK Financial. Mr. Lybarger served as its first president and chief operating officer, in addition to continuing to hold that title for Bank of Oklahoma. He became the chief executive officer for BOK Financial and Bank of Oklahoma in 1996. Lybarger earned B.A. and M.B.A. degrees from the University of Kansas, and a Certification from the Stonier Graduate School of Banking at Rutgers University.

Mr. Lybarger has also been an industry and community leader for decades and has held leadership positions at a number of organizations, including serving on the Federal Advisory Council (a 12-member council which consults and advises the Federal Reserve Board of Governors in Washington, DC), the Executive Committee of the Financial Institutions Division of the American Bankers Association, Chairman of the Tulsa Stadium Trust, Chairman of the Tulsa Metro Chamber, Chairman of the Oklahoma State Chamber, Chairman of The Oklahoma Business Roundtable, and Chairman of Tulsa Area United Way.

Mr. Lybarger's experience leading BOK Financial and his deep knowledge and relationships in the energy industry qualifies him to serve on our board of directors. We believe Mr. Lybarger's prior and current service as a director of public and private companies will suit him to serve as a director.

John T. McNabb II is a director of Cypress Energy Partners GP, LLC, and serves as Chairman of our conflicts committee. Mr. McNabb is Chairman and CEO of Willbros Group, an engineering and construction firm, which focuses on the energy segment worldwide, and is senior advisor to Duff & Phelps LP, a global independent provider of financial advisory and investment banking services. Prior to joining Duff and Phelps, he was founder and chairman of the board of directors of Growth Capital Partners, LP, an investment and merchant banking firm that provided financial advisory services to middle-market companies throughout the United States for 19 years. Previously he was managing director for Bankers Trust New York Corporation and a board member of BT Southwest, Inc., the southwest U.S. merchant banking affiliate of Bankers Trust, from 1989 to 1992. Mr. McNabb started his career, after serving in the U.S. Air Forces during the Vietnam conflict, with Mobil Oil in its exploration and production division. He had served on the boards of eight public companies, including Hiland Partners, LP, Warrior Energy Services Corporation, Hugoton Energy Corporation, and Vintage Petroleum, Inc. and currently serves on the board and was formerly lead director of Continental Resources, Inc. Mr. McNabb earned both his undergraduate and MBA degrees from Duke University.

Mr. McNabb's service as a partner in two independent exploration and production companies, and his extensive experience leading management teams and serving as a financial advisor to energy industry companies enables him to chair our conflicts committee with respect to industry matters. We believe Mr. McNabb's significant prior and current service on the boards of numerous public and private companies, including his prior service in chairing the audit committees of three public companies qualifies him as one of our audit committee financial experts, and his extensive knowledge of the petroleum industry, finance, corporate governance and oversight matters will qualify him to serve as a director.

Charles C. Stephenson, Jr. has served as a director on the board of Cypress Energy Partners GP, LLC since January 14, 2014. Since 2006, Mr. Stephenson has served as Chairman of the Board of Premier Natural Resources, an independent oil and gas company of which he is also a co-founder. Mr. Stephenson is an owner of Regent Private Capital II LLC and was a co-founder and director of Growth Capital Partners, an investment and merchant banking firm. From 1983 to 2006, Mr. Stephenson worked for Vintage Petroleum, Inc., which he founded and for which he served as Chairman of the Board, President and Chief Executive Officer at the time of its sale to Occidental Petroleum in 2006. Mr. Stephenson received a B.S. in petroleum engineering from the University of Oklahoma. Mr. Stephenson is a member of the Society of Petroleum Engineers and has served on the board of the National Petroleum Council.

Mr. Stephenson's experience founding two successful energy companies, and his decades of experience leading management teams and serving as chief executive officer, enables him to serve on our board of directors. We believe Mr. Stephenson's significant prior and current experience as a senior executive in the energy industry will suit him to serve as director.

Board Leadership Structure

The chief executive officer of our general partner currently serves as the chairman of the board. The board of directors of our general partner has no policy with respect to the separation of the offices of chairman of the board of directors and chief executive officer. Instead, that relationship is defined and governed by the amended and restated limited liability company agreement of our general partner, which permits the same person to hold both offices. Directors of the board of directors of our general partner are designated or elected by a wholly owned subsidiary of Holdings. Accordingly, unlike holders of common stock in a corporation, our unitholders will have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement.

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Board Role in Risk Oversight

Our organizational governance guidelines will provide that the board of directors of our general partner are responsible for reviewing the process for assessing the major risks facing us and the options for their mitigation. This responsibility will be largely satisfied by our audit committee, which is responsible for reviewing and discussing with management and our registered public accounting firm our major risk exposures and the policies management has implemented to monitor such exposures, including our financial risk exposures and risk management policies

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our general partner's board of directors and officers, and persons who beneficially own more than 10% of a class of our equity securities registered pursuant to Section 12 of the Exchange Act to file certain reports with the SEC and NYSE concerning beneficial ownership of such securities. To our knowledge, based solely on a review of the copies of such reports furnished to us and written representations by our directors and officers, we believe that all reporting obligations of our general partner's directors and officers and our greater than 10% unitholders under Section 16(a) were satisfied during the year ended December 31, 2014.

Corporate Governance

The board of directors of our general partner has adopted Corporate Governance Guidelines that outline important policies and practices regarding our governance and a Code of Business Conduct and Ethics that applies to the directors, officers and employees of our general partner and its affiliates and us.

We make available free of charge, within the "Corporate Governance" section of our website at www.cypressenergy.com, the Corporate Governance Guidelines, the Code of Business Conduct and Ethics and our Audit Committee Charter. The information contained on, or connected to, our website is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

ITEM 11. EXECUTIVE COMPENSATION

We are an "emerging growth company" as defined under the JOBS Act. As such, we are permitted to meet the disclosure requirements of Item 402 of Regulation S-K by providing the reduced disclosures required of a smaller reporting company.

Compensation Overview

Executive Compensation

We do not directly employ any of the persons responsible for managing our business. Our general partner, under the direction of its board of directors, or the board, is responsible for managing our operations and CEM LLC employs the employees that operate our business. The compensation payable to the officers of our general partner is paid by CEM LLC and such payments are reimbursed by us. However, we sometimes refer to the employees and officers of our general partner as our employees and officers in this report.

This executive compensation disclosure provides an overview of the executive compensation program for our named executive officers identified below. For the year ended December 31, 2014, our named executive officers, or our NEOs, were:

- Peter C. Boylan III, our President and Chief Executive Officer;
- G. Les Austin, our Vice President and Chief Financial Officer; and
- Richard M. Carson, our Vice President and General Counsel.

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Summary Compensation Table For 2014

The following table sets forth certain information with respect to the compensation paid to our NEOs for the years ended December 31, 2014 and 2013.

Name and Principal Position	Year	Salary	Bonus (1)	Unit Awards (2)	All Other Compensation (3)	Total
Peter C. Boylan III	2014	$352,512	$—	$—	$ 2,390	$354,902
President and Chief Executive Officer	2013	$258,420	$—	$—	$ 28,676	$287,096
G. Les Austin	2014	$211,667	$70,000	$599,712	$ 188	$881,567
Vice President and Chief Financial Officer	2013	$175,000	$—	$—	$ —	$175,000
Richard M. Carson	2014	$211,458	30,000	$272,488	$ 186	$514,132
Vice President and General Counsel (4)	2013	$44,000	—	$100,046	$ —	$144,046

(1) Represents cash bonus awards paid to Mr. Austin and Mr. Carson in February 2014. For additional information, see “Bonus awards” below.

(2) Represents the grant date fair value of awards granted under the Cypress Energy Partners, L.P. 2013 Long-Term Incentive Plan as determined in accordance with FASB ASC Topic 718, as well as the change in grant date fair value associated with the conversion of previously granted CEP LLC awards into subordinated units in us for Mr. Austin and Mr. Carson, which amounts consist of $344,081 for Mr. Austin and $158,213 for Mr. Carson. For additional information, please see Note 10 to the Consolidated Financial Statements included in Item 8 in this Annual Report.

(3) Represents cash payments provided for healthcare premiums for Mr. Boylan. These payments were made in lieu of our providing any health or welfare benefits to Mr. Boylan. Represents cash value of long-term disability insurance for Mr. Austin and Mr. Carson.

(4) Mr. Carson commenced service as our Vice President and General Counsel in September 2013 and became a full time employee of CEM on January 1, 2014. The amount shown represents payments made in respect of Mr. Carson’s part-time service with us during 2013 pursuant to an arrangement with Mr. Carson’s former law firm.

Narrative Disclosure to Summary Compensation Table

Elements of the compensation program. For 2014, the primary elements of compensation for our NEOs included base salary, cash bonus awards and equity awards.

Base compensation for 2014. Base salaries for our NEOs were originally set at modest levels, primarily due to our limited operating history at the time such salaries were determined. Salaries were increased in February 2014 following the IPO to bring them more in line with competitive salaries in our industry.

The following table sets forth the current annualized base salary rates for our NEOs as of December 31, 2014:

Name and Principal Position	Current Base Salary

Peter C. Boylan III	
President and Chief Executive Officer	$361,066
G. Les Austin	
Vice President and Chief Financial Officer	$215,000
Richard M. Carson	
Vice President and General Counsel	$212,500

Bonus awards. Our NEOs are eligible to receive discretionary cash bonus awards as our general partner's board of directors may determine from time to time. For 2014, Mr. Austin and Mr. Carson received cash bonus awards. Mr. Austin's and Mr. Carson's bonus awards were granted based on a subjective performance determination in the amounts of $70,000 and $30,000, respectively.

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Discretionary long-term equity incentive awards. In December 2012, in connection with his commencement of employment, Mr. Austin, received a one-time award of Class C Units in CEP LLC, which were intended to allow Mr. Austin to share in the future equity appreciation of CEP LLC from and after the date of grant of such Class C Units. Mr. Carson received a similar award in connection with his commencement of service in September 2013. The awards vest in three equal annual installments on the third, fourth and fifth anniversary of the grantee's commencement of service with us, respectively. In connection with our IPO, the Class C units in CEP LLC were converted into subordinated units in us on an equivalent value basis, based on the per unit price in our IPO and with the same vesting terms as applied to the Class C Units. Mr. Austin's award converted into 30,143 subordinated units and Mr. Carson's award converted into 14,308 subordinated units.

In connection with our IPO, we adopted the Cypress Energy Partners, L.P. 2013 Long-Term Incentive Plan, or the LTIP, under which we make periodic grants of equity and equity-based awards in us to our NEOs and other key employees and other service providers. In addition to the equity awards received by Mr. Austin and Mr. Carson in connection with the conversion of previously issued awards in CEP LLC described above, in 2014 we granted long-term incentive awards to Mr. Austin and Mr. Carson in the form of phantom units. The phantom units are scheduled to vest in three equal annual installments on each of the third, fourth and fifth anniversaries of the grant date, subject to the NEO's continued employment with us on the applicable vesting date and potential accelerated vesting as described below under "Severance and change in control arrangements."

Outstanding Equity Awards at December 31, 2014

The following table provides information regarding the outstanding and unvested long-term equity incentive awards held by our NEOs as of December 31, 2014. None of our NEOs held any option awards that were outstanding as of December 31, 2014.

		Unit Awards		
Name	Grant Date	Number of Units That Have not Vested (#)		Market Value of Units That Have Not Vested ($) (4)
Peter C. Boylan III (1)	—	—		$—
G. Les Austin	2/1/2014	10,283	(2)	$147,047
	12/31/2014	4,440	(5)	63,492
	—	30,143	(3)	431,045
Richard M. Carson	2/1/2014	2,571	(2)	$36,765
	12/31/2014	4,440	(5)	63,492
	—	14,308	(3)	204,604

(1) Mr. Boylan held no unvested equity awards as of December 31, 2014. As our co-founder, he owns part of Holdings.

(2) Represents phantom units granted under the LTIP and scheduled to vest in three equal annual installments on the third, fourth and fifth anniversaries of the grant date.

(3) Represents subordinated units in us into which previously issued awards in CEP LLC that were outstanding as of December 31, 2013 were converted upon the closing of our IPO on January 21, 2014 based upon the IPO price of $20.00 per common unit. The subordinated units for Mr. Austin are scheduled to vest in three equal annual installments on each of October 1, 2015, 2016 and 2017. The subordinated units for Mr. Carson are scheduled to vest in three equal annual installments on each of September 30, 2016, 2017 and 2018.

(4) Amount shown reflects the per-unit value based upon the December 31, 2014 closing price of $14.30 per common unit.

(5) Represents phantom units granted under the LTIP which vest 100% on June 30, 2016.

Severance and change in control arrangements. None of our NEOs has entered into any employment or severance agreements with our general partner or any of its affiliates.

The terms of Mr. Austin's and Mr. Carson's long-term equity incentive awards provide that in the event of a change in control of the Partnership, their awards would become fully vested, effective as of immediately prior to such change in control.

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Retirement, Health, Welfare and Additional Benefits

We provide a basic benefits package that is available to all full-time employees, which currently includes medical, dental, disability and life insurance and a 401(k) plan. We do not expect to maintain a defined benefit pension plan for our executive officers, because we believe such plans primarily reward longevity rather than performance.

Director Compensation

Officers, employees or paid consultants or advisors of us or our general partner or its affiliates who also serve as directors do not receive additional compensation for their service as directors. Our independent directors who are not officers, employees or paid consultants or advisors of us or our general partner or its affiliates receive cash and equity-based compensation for their services as directors.

Our non-employee director compensation program consists of the following:

- an annual cash retainer of $25,000,

- an additional annual cash retainer of (i) $5,000 for service as the chair of our conflicts committee and (ii) $7,500 for service as the chair of our audit committee, and

- an annual equity-based award granted under our LTIP, having a value as of the grant date of $50,000. Equity-based awards are subject to vesting in equal annual installments over a period of three years, based upon continued service as an independent director.

Non-employee directors also receive reimbursement for out-of-pocket expenses associated with attending such board or committee meetings and director and officer liability insurance coverage. Each director will be fully indemnified by us for actions associated with being a director to the fullest extent permitted under Delaware law.

In addition to the compensation described above, Mr. McNabb and Mr. Lybarger were awarded one phantom unit under the LTIP for each common unit they purchased in the directed unit program or in the open market from the time of our IPO through May 31, 2014 for a total of 15,000 phantom units for Mr. McNabb and 4,000 phantom units for Mr. Lybarger. The phantom units will vest in three equal annual installments.

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The following table provides information regarding the compensation earned by our non-employee directors during the year ended December 31, 2014.

Name	Fees Earned or Paid in Cash ($)	Unit Awards ($)(1)	Total
Henry Cornell	$25,000	$21,540	$46,540
Stan Lybarger	$32,500	$100,505	$133,005
John T. McNabb II	$30,000	$297,728	$327,728

(1) Represents the grant date fair value of the awards, as determined in accordance with FASB ASC Topic 718. For additional information, please see Note 10 to the Consolidated Financial Statements included in Item 8 in this Annual Report.

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Compensation Committee Interlocks and Insider Participation

As a limited partnership, we are not required by the NYSE to establish a compensation committee. Mr. Boylan III, who serves as the Chairman of the Board participates in his capacity as a director in the deliberations of the Board concerning executive officer compensation. In addition, Mr. Boylan III makes recommendations to the Board regarding named executive officer compensation but abstains from any decision regarding his own compensation.

Compensation Committee Report

Neither we nor our general partner has a compensation committee. The board of directors of our general partner has reviewed and discussed the Compensation Overview set forth above and based on this review and discussion has approved it for inclusion in this Annual Report on Form 10-K.

Members of the Board of Directors of Cypress Energy Partners GP, LLC

Peter C. Boylan III	Henry Cornell	Phil Gisi
Stan Lybarger	John T. McNabb II	Charles C. Stephenson, Jr.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table sets forth the beneficial ownership of units of Cypress Energy Partners, L.P., as of March 15, 2015, held by beneficial owners of 5.0% or more of the units, by each director and named executive officer of Cypress Energy Partners GP, LLC, our general partner, and by all directors and executive officers of our general partner as a group. The percentage of units beneficially owned is based on a total of 5,913,000 common units and 5,913,000 subordinated units outstanding.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote or to direct the voting of such security, or "investment power," which includes the power to dispose of or to direct the disposition of such security. In computing the number of common units beneficially owned by a person and the percentage ownership of that person, common units subject to options or warrants held by that person that are currently exercisable or exercisable within 60 days of March 15, 2015, if any, are deemed outstanding, but are not deemed outstanding for computing the percentage ownership of any other person. Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable. The address for each of the beneficial owners below is 5727 S. Lewis Avenue, Suite 500, Tulsa, Oklahoma 74105.

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Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Common Units and Subordinated Units Beneficially Owned
Cypress Energy Holdings, LLC (1)(2)	1,344,650	22.7 %	5,612,699	94.7 %	58.8 %
Peter C. Boylan III	6,000	*	—	—	*
G. Les Austin	7,500	*	30,143	*	*
Richard M. Carson	2,500	*	14,308	*	*
Jeff English	200	*	—	—	*
Don LaBass	—	—	—	—	—
Henry Cornell	—	—	—	—	—
Phil Gisi	20,000	*	—	—	*
John T. McNabb II	18,000		—	—	
Stan Lybarger	13,921	*	—	—	—
Charles C. Stephenson, Jr.	204,400	3.5 %	198,400	3.4 %	3.4 %
All directors and executive officers as a group (consisting of 10 persons)	272,521	4.6 %	242,851	4.1 %	4.4 %

* An asterisk indicates that person or entity owns less than one percent.

(1) Cypress Energy Holdings, LLC owns 100.0% of Cypress Energy Holdings II, LLC, which owns 100.0% of our general partner. Cypress Energy Holdings II, LLC owns 11.4% of our common units and 83.4% of our subordinated units. The following table sets forth the beneficial ownership of Cypress Energy Holdings, LLC:

Name of Beneficial Owner	Ownership Interest Ratio (a)
Cynthia A. Field Trust (b)	36.750 %
Charles C. Stephenson, Jr.	27.468 %
CEP Capital Partners, LLC (c)	24.500 %
Henry Cornell	2.000 %
Lawrence D. Field, Jr. Trust – 2007 (b)	1.547 %
Alex S. Field Trust – 2007 (b)	1.547 %
Andrew M. Field Trust – 2007 (b)	1.547 %
Corry C. Stephenson Trust – 2007 (b)	1.547 %
Kelly C. Stephenson Trust – 2007 (b)	1.547 %
Julie A. Stephenson Trust – 2007 (b)	1.547 %

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(a) Cypress Energy Holdings, LLC is managed by a three-member board of directors consisting of Peter C. Boylan III, Lawrence D. Field and Charles C. Stephenson, Jr. The election of each director requires the affirmative vote of members representing at least a majority of the voting ratio of Holdings and the concurrence of CEP Capital Partners, LLC.

(b) Voting rights of the trust are exercised by Cynthia A. Field, as trustee.

(c) CEP Capital Partners, LLC is owned and controlled by affiliates of Peter C. Boylan III, our Chairman and Chief Executive Officer.

(2) Cypress Energy Holdings, LLC owns 100.0% of Cypress Energy Investments, LLC, which owns 100.0% of CEP TIR. CEP TIR owns 11.4% of our common units and 11.4% of our subordinated units.

Securities Authorized for Issuance under Equity Compensation Plans

In connection with the consummation of our IPO on January 21, 2014, the board of directors of our general partner adopted the 2013 Long-Term Incentive Plan. The following table provides certain information with respect to this plan as of December 31, 2014:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights		Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders (1)	157,281	(2)	N/A	1,025,319
Equity compensation plans not approved by security holders	—		—	—
Total	157,281		N/A	1,025,319

(1) Our general partner adopted the Cypress Energy Partners, L.P. 2013 Long-Term Incentive Plan in January 2014 in connection with the completion of our IPO.
(2) Amount shown represents outstanding phantom units. The phantom units do not have an exercise price.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Conflicts of Interest and Duties

Under our partnership agreement, our general partner has a contractual duty to manage us in a manner it believes is in the best interests of our partnership and unitholders. However, because our general partner is a wholly owned subsidiary of Holdings, the officers and directors of our general partner have a duty to manage the business of our general partner in a manner that is in the best interests of Holdings. As a result of this relationship, conflicts of interest may arise in the future between us and our unitholders, on the one hand, and our general partner and its affiliates, including Holdings, on the other hand. For example, our general partner will be entitled to make determinations that affect the amount of cash distributions we make to the holders of common units, which in turn has an effect on whether our general partner receives incentive cash distributions. In addition, our general partner may determine to manage our business in a way that directly benefits Holdings’ businesses, rather than indirectly benefitting Holdings solely through its ownership interests in us. We expect that any future decision by Holdings in this regard will be made on a case-by-case basis. However, all of these actions are permitted under our partnership agreement and will not be a breach of any duty (fiduciary or otherwise) of our general partner.

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Delaware law provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict or eliminate the duties (including fiduciary duties) otherwise owed by the general partner to limited partners and the partnership. As permitted by Delaware law, our partnership agreement contains various provisions replacing the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing the duties of the general partner and contractual methods of resolving conflicts of interest. The effect of these provisions is to restrict the remedies available to unitholders for actions that might otherwise constitute breaches of our general partner's fiduciary duties. Our partnership agreement also provides that affiliates of our general partner, including Holdings and its controlled affiliates, are permitted to compete with us, and neither our general partner nor its affiliates have any obligation to present business opportunities to us. By purchasing a common unit, the purchaser agrees to be bound by the terms of our partnership agreement, and pursuant to the terms of our partnership agreement each holder of common units consents to various actions and potential conflicts of interest contemplated in our partnership agreement that might otherwise be considered a breach of fiduciary or other duties under Delaware law.

The general partner and its controlled affiliates own 1,344,650 common units and 5,612,699 subordinated units, representing a 58.8% limited partner interest in us. In addition, our general partner owns a 0.0% non-economic general partner interest in us.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its controlled affiliates in connection with the formation, ongoing operation, and liquidation of Cypress Energy Partners, L.P. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Formation Stage

The consideration received by our general partner and its controlled affiliates prior to or in connection with the IPO for the contribution of the assets and liabilities to us	1,344,650 common units; 5,612,699 subordinated units; 0.0% non-economic general partner interest; the incentive distribution rights; and a cash payment of approximately $80.2 million from the proceeds of the IPO.

Operational Stage

Distributions of available cash to our general partner and its controlled affiliates	We will generally make cash distributions to the unitholders pro rata, including Holdings and its controlled affiliates, as holder of an aggregate of 1,344,650 common units and 5,612,699 subordinated units. In addition, if distributions exceed the minimum quarterly distribution and target distribution levels, the incentive distribution rights held by our general partner will entitle our general partner to increasing percentages of the distributions in steps, up to 50% of the distributions above the highest target distribution level. During the period of January 21, 2014 through December 31, 2014 (the pro-rata period from the closing of our IPO through year end) the distribution on all of our outstanding units for four quarters, our general partner and its affiliates received approximately $10.5 million.

Payments to our general partner and its affiliates	Under our partnership agreement, we are required to reimburse our general partner and its affiliates for all costs and expenses that they incur on our behalf for managing and controlling our business and operations. Except to the extent specified under our amended and restated omnibus agreement, our general partner determines the amount of these expenses and such determinations must be made in good faith under the terms of our partnership agreement. Under our amended and restated omnibus agreement, we reimburse our general partner a $3.8 million annual administrative fee for expenses incurred by it and their respective affiliates in providing certain partnership overhead services to us, including the provision of executive management services by certain officers of our general partner for the period of January 21, 2014 through December 31, 2014 (the pro-rata period from the closing of our IPO through year end). This fee also included $2.0 million in annual cash expense we incurred as a result of being a publicly traded partnership. The annual administrative fee is subject to 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. Please read "Agreements with Affiliates — Omnibus Agreement" below and "Compensation Overview." The fee has been increased one percent (1.0%) for 2015.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation Stage	
Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

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Agreements with Affiliates

On January 21, 2014, we and other parties entered into the various agreements associated with the closing of our IPO, including the vesting of assets in, and the assumption of liabilities by, us and our subsidiaries.

Omnibus Agreement

We are party to an amended and restated omnibus agreement with Holdings, CEM LLC, CEP LLC, our general partner, CEP TIR, the TIR Entities, Charles C. Stephenson, Jr. and Cynthia A. Field that address the following matters, among other things:

our payment of an annual administrative fee to be paid in quarterly installments to Holdings for providing us with certain partnership overhead services, including for certain executive management services by certain officers of our general partner, and compensation expense for all employees required to manage and operate our business. This fee also includes the incremental general and administrative expenses we will 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 saltwater disposal and other water and environmental services and pipeline inspection and integrity services; and

indemnification of us by Holdings for certain environmental and other liabilities, including events and conditions associated with our operation of assets that occur 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, our amended and restated 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 our amended and restated 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 amend our amended and restated omnibus agreement; however, amendments that the general partner determines are adverse to our unitholders will also require the approval of the conflicts committee.

Payment of Administrative Fee and Reimbursement of Expenses

We pay an annual administrative fee in quarterly installments to Holdings. The administrative fee is intended to reimburse Holdings for providing us with certain partnership overhead services, including for certain executive management services by certain officers of our general partner, and for paying on our behalf all compensation expense for the employees required to manage and operate our business and all expenses incurred by us as a result of our becoming and continuing as a publicly traded entity, including costs associated with Exchange Act filings, independent public accounting firm fees, partnership governance and compliance, registrar and transfer agent fees, tax return and Schedule K-1 preparation and distribution, legal fees and director compensation.

The amount of the administrative fee is subject to increase each year by the percentage equal to the increase, if any, in the PPI plus 1.0%. In addition, the administrative fee may be increased with the approval of our conflicts committee in the event of an expansion of our operations, including though acquisitions or internal growth, a change in applicable law or regulation, or as agreed upon by us and our general partner. The fee has been increased by 1.0% in 2015.

Right of First Offer

Under our amended and restated omnibus agreement, if Holdings or its controlled subsidiaries decide to sell, transfer or otherwise dispose of any of the assets or entities listed below within a five-year period following the closing of the IPO, Holdings will provide notice to us of such intended disposition and provide us with the opportunity to make the first offer on:

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- any assets used in, or entities engaged primarily in, providing saltwater disposal and other water and environmental services to U.S. onshore oil and natural gas producers and trucking companies in the U.S., including any assets or entities currently owned by or acquired from SBG Energy Services, LLC; and

- any assets used in, or entities engaged primarily in, providing pipeline inspection and integrity services.

After receiving the notice of Holdings' intention to sell or transfer such assets, we will have 45 days to make an offer to Holdings with our proposed terms for the acquisition. The consummation and timing of any acquisition by us of the assets covered by our right of 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.

Indemnification

Under our amended and restated omnibus agreement, Holdings will indemnify us, without giving effect to any cap, for the following matters:

- Environmental: all known and unknown environmental liabilities that are associated with the ownership or operation of our assets and due to occurrences on or before the closing of the IPO. Indemnification for any unknown environmental liabilities will be limited to liabilities arising out of occurrences in existence before the closing of the IPO and identified prior to the third anniversary of the closing of the IPO, and will be subject to an aggregate deductible of $350,000 before we are entitled to indemnification;

- Retained Assets: all events and conditions associated with any assets retained by Holdings regardless of when they occur;

- *IPO Transactions*: for a period of five years after the closing of the IPO to the extent not covered by other indemnifications in our amended and restated omnibus agreement, the formation transactions, asset contributions and ownership of the contributed assets prior to the closing, as well as any event or condition that arise out of ownership of the contributed assets prior to closing;

- Titles and Permits: for a period of five years after the closing of the IPO, any failure to have at the closing of the offering any title, right of way, consent, license, permit, or approval necessary for us to own or operate our assets in substantially the same manner that the assets were owned or operated immediately prior to the closing of the IPO and as described in this report, subject to an aggregate deductible of $500,000;

- Litigation: any legal proceedings attributable to ownership or operation of the contributed assets prior to the closing of the IPO, except that indemnification for any legal proceeding not known at the time of the closing of the IPO is subject to an aggregate deductible of $250,000;

- TIR Restructuring Transactions: the acquisition of the shares in Tulsa Inspection Resources, Inc. and the merger of Tulsa Inspection Resources, Inc. with the TIR Entities; and

- Tax Liabilities: for a period up to 60 days past the expiration of any applicable statute of limitations, any tax liability attributable to the assets contributed to us arising prior to the closing of the IPO or otherwise related to Holdings' contribution of those assets to us in connection with the IPO.

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We have agreed to indemnify Holdings, without giving effect to any deductible or cap, 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 as described above.

Contribution Agreement

In connection with the closing of the IPO, we entered into a contribution agreement with Holdings and certain of its subsidiaries that effected the restructuring transactions, including the transfer of CEP LLC to us and the use of the net proceeds of the IPO.

Relationships with SBG

One of our directors, Phil Gisi, is also a director and executive officer of SBG Energy Services, LLC ("SBG"), and Rud Transportation LLC ("Rud"), an affiliate of SBG. As discussed below, we have commercial arrangements with SBG, SBG Disposal ("SBG Disposal") LLC and Rud, and we believe the terms of these transactions are similar to what would have been obtained from an unaffiliated third party.

SBG Management Services Agreement

On December 31, 2012, Holdings, acting through one of its subsidiaries, entered into a management services agreement with SBG Disposal. Pursuant to this agreement, SBG Disposal provided day-to-day oversight, management, development, construction and operations of the SWD facilities we acquired from SBG. Effective October 1, 2013, SBG Disposal contributed this agreement to CES LLC, which is owned 49.0% by SBG Disposal. All personnel providing such services became employees of Cypress Energy Management – Bakken Operations, LLC, a wholly owned subsidiary of CEM LLC, on December 22, 2013. This agreement has a five year term that will automatically renew for 90 day periods unless terminated by either party with written notice. Prior to the contribution of the management agreement, SBG Disposal was paid a monthly fee equal to 4.75% of gross revenues in addition to reimbursable expenses such as direct staffing expenses and supplies.

SBG Option Agreement

On December 31, 2012, CEP LLC, acting through a subsidiary, entered into an option agreement with SBG. Pursuant to this agreement, SBG, the sole member of SBG Disposal, granted CEP LLC the option to purchase 51.0% of the membership interests in SBG Disposal for $500,000. On December 6, 2013, CEP LLC, acting through a subsidiary, effectively exercised this option by entering into an asset contribution and assumption agreement with SBG Disposal, or the asset contribution agreement, through which SBG Disposal conveyed certain of its assets, including all fixed assets, to CES LLC in exchange for a 49.0% membership interest in CES LLC and a cash payment from CES LLC of $500,000. This transaction was effective October 1, 2013. The assets contributed included a 25.0% non-controlling interest in an SWD facility in Watford City, North Dakota and five management services agreements related to SBG Disposal's management of ten SWD facilities in North Dakota, eight of which we own. CES LLC is consolidated in our financial statements beginning October 1, 2013.

Pursuant to the CES LLC operating agreement between CEP LLC and SBG Disposal, CES LLC is managed by a board of three managers, two of which are appointed by CEP LLC, and one of which is appointed by SBG Disposal. All management decisions of CES LLC are made by the majority vote of the board of managers; however, amending CES LLC's organizational documents in a way that adversely impacts SBG Disposal, or entering into or amending contracts with CEP LLC or one of its affiliates, other than in the general course of business, also requires the affirmative vote of the manager appointed by SBG Disposal. Pursuant to the operating agreement, the available cash of CES LLC shall be distributed to the members pro rata in accordance with their respective membership interests.

The CES LLC operating agreement also provides CEP LLC with the right to purchase SBG Disposal's 49.0% membership interest in CES LLC at fair market value. If CEP LLC exercises this call option, CEP LLC is required under the operating agreement to provide notice to SBG Disposal of its exercise of the call option along with its calculation of the fair market value of the 49.0% membership interest to be acquired. If SBG Disposal objects to CEP LLC's fair market value calculation, the fair market value of the membership interest shall be calculated by an appraiser pursuant to the appraisal provisions in the operating agreement.

SBG Omnibus Option Agreement

On December 31, 2012, Holdings, acting through one of its subsidiaries, entered into an omnibus option agreement with SBG and its owners, including Philip Gisi. Pursuant to this agreement, Holdings has the first right to negotiate with the owners of SBG if they decide to sell the membership interest in SBG. The agreement also provides Holdings with the first right to negotiate with SBG if SBG decides to sell any of the following assets:

- its membership interest in Rud, a wholly owned subsidiary of SBG that owns trucking equipment engaged in hauling water to and from producers in North Dakota;

- all of SBG's right to any water pipeline construction, development or acquisition opportunity;

- all of SBG's interest in its gas and diesel wholesale venture; and

- all of SBG's interest in its hot water and rail spur ventures.

Holdings also acquired the right to purchase certain other assets that it does not currently anticipate exercising.

The first rights to negotiate described above continue in each case until December 31, 2017. Additionally, pursuant to the omnibus option agreement, Holdings has the right to purchase part of SBG and the option price to purchase the first 5.0% of SBG is $10 per membership unit of SBG. In addition, the option price to purchase the first 5.0% of any of the other assets set forth in the omnibus option agreement is set at 5.0% of the actual cost the owners of such asset expended to acquire the asset. In addition, the omnibus option agreement provides Holdings with a right of first refusal to match the terms on which SBG intends to sell one of the above-listed assets to a third party if Holdings is unable to reach an agreement to buy that asset from SBG in the first instance.

Assignment and Assumption Agreements

On November 7, 2013, the lenders of the TIR Entities' prior mezzanine facilities irrevocably assigned and sold to TIR Capital Partners, LLC, ("TIR Capital"), all of the lenders' rights and obligations under the mezzanine facilities, and TIR Capital irrevocably purchased and assumed all of such rights and obligations for approximately $20.0 million. From November 7 to December 24, 2013 when the mezzanine facilities were repaid and retired from borrowings under the credit agreement, the TIR Entities paid TIR Capital, as the new lender under the mezzanine facilities, interest on the outstanding balance of the mezzanine facilities at a rate of 14.7%, or an aggregate amount of approximately $0.4 million. In addition, on December 5, 2013, Wells Fargo irrevocably assigned and sold to TIR Capital all of its rights and obligations under the TIR Entities' prior revolving credit facility, and TIR Capital irrevocably purchased and assumed all of such rights and obligations for approximately $38.0 million. From December 5 to December 24, 2013 when the revolving credit facility was repaid and retired from borrowings under the credit agreement, the TIR Entities paid TIR Capital, as the new lender under the revolving credit facility, interest on all outstanding advances at the annualized rate of LIBOR plus 4.0% for previously outstanding U.S. dollar advances and at the annualized rate of CDOR plus 4.55% for previously outstanding Canadian dollar advances, or an aggregate amount of approximately $0.1 million. TIR Capital was a newly formed financing entity owned and controlled jointly by Peter C. Boylan III, our Chief Executive Officer and an indirect owner of our general partner, and Charles C. Stephenson, Jr., a director of our general partner, an indirect owner of our general partner and a partial owner of the TIR Entities.

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Mr. Boylan's Sharing Interest in Holdings

In connection with the formation of Holdings, as a co-founder, Mr. Boylan, our Chairman and Chief Executive Officer was issued a limited liability company interest in Holdings, based upon his arms' length negotiation with Charles C. Stephenson, Jr., the other co-founder of Holdings. The terms of Mr. Boylan's limited liability company interest provided that Mr. Boylan initially receive a 5.0% sharing interest in the profits and losses of Holdings and in any distributions made by Holdings in respect of its equity securities, which sharing interest increasing to 24.50% effective on the earlier of April 1, 2015 or the IPO of our equity securities. As a result, Mr. Boylan's sharing interest in Holdings was increased to 24.50% (25% prior to admission of Henry Cornell) in connection with the consummation of the IPO.

Procedures for Review, Approval and Ratification of Related Person Transactions

The board of directors of our general partner adopted a related party transactions policy in connection with the closing of the IPO that provides that the board of directors of our general partner or its authorized committee will review on at least a quarterly basis all related person transactions that are required to be disclosed under SEC rules and, when appropriate, initially authorize or ratify all such transactions. In the event that the board of directors of our general partner or its authorized committee considers ratification of a related person transaction and determines not to so ratify, the code of business conduct and ethics will provide that our management will make all reasonable efforts to cancel or annul the transaction.

The related party transactions policy provides that, in determining whether or not to recommend the initial approval or ratification of a related person transaction, the board of directors of our general partner or its authorized committee should consider all of the relevant facts and circumstances available, including (if applicable) but not limited to: (1) whether there is an appropriate business justification for the transaction; (2) the benefits that accrue to us as a result of the transaction; (3) the terms available to unrelated third-parties entering into similar transactions; (4) the impact of the transaction on a director's independence (in the event the related person is a director, an immediate family member of a director or an entity in which a director or an immediate family member of a director is a partner, shareholder, member or executive officer); (5) the availability of other sources for comparable products or services; (6) whether it is a single transaction or a series of ongoing, related transactions; and (7) whether entering into the transaction would be consistent with the code of business conduct and ethics.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

We have engaged Ernst & Young LLP as our independent registered public accounting firm. The following table sets forth fees we have paid to Ernst & Young LLP for the years ended December 31, 2014 and 2013.

Audit and Non-Audit Fees

	2014	2013
	(in thousands)	
Audit fees (1)	$959	$1,968
Audit-related fees (2)	28	145
Tax fees (3)	303	493
All other fees	-	-
Total	$1,290	$2,606

(1)

Fees for audit services include fees associated with the annual audit of Cypress Energy Partners, L.P. and reviews of the Partnership's quarterly reports.

(2) Include fees related to acquisition due diligence and accounting consultations.

(3) Includes fees for tax services for Cypress Energy Partners, L.P. and affiliates in connection with tax compliance, tax advice, and tax planning.

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Audit Committee Pre-Approval Policies and Procedures

Our audit committee has adopted an audit committee charter which requires the audit committee to pre-approve all audit and non-audit services to be provided by our independent registered public accounting firm. The audit committee does not delegate its pre-approval responsibilities to management or to an individual member of the audit committee. Since our audit committee was not established until January 2014, our board of directors pre-approved all services reported in the audit, audit-related, tax, and all other fees categories for 2013 above.

PART IV.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents to be filed as part of this Annual Report

1. Financial Statements.

2. Financial Statement Schedules: Financial Statement Schedules are omitted because they are not required, not significant, not applicable or the information is shown in another schedule, the financial statements or the notes to consolidated financial statements.

3. Exhibits: See “Exhibit Index” below.

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Exhibit Index

Exhibit number	Description
3.1	Limited Partnership Agreement of Cypress Energy Partners, L.P. (incorporated by reference to Exhibit 3.1 of our Registration Statement on Form DRS filed on September 20, 2013)
3.2	First Amended and Restated Agreement of Limited Partnership of Cypress Energy Partners, L.P. dated as of January 21, 2014 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on January 27, 2014)
3.3	Certificate of Formation of Cypress Energy Partners GP, LLC (incorporated by reference to Exhibit 3.5 of our Registration Statement on Form S-1/A filed on December 17, 2013)
3.4	Amended and Restated Limited Liability Company Agreement of Cypress Energy Partners GP, LLC dated as of January 21, 2014 (incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed on January 27, 2014)
3.5	Certificate of Limited Partnership of Cypress Energy Partners, L.P. (incorporated by reference to Exhibit 3.7 of our Registration Statement on Form S-1/A filed on December 17, 2013)
10.1	Contribution, Conveyance and Assumption Agreement dated as of January 21, 2014, by and among Cypress Energy Partners, L.P., Cypress Energy Holdings, LLC, Cypress Energy Holdings II, LLC, Cypress Energy Partners, LLC, Cypress Energy Partners GP, LLC, Cypress Energy Partners – SBG, LLC, Cypress Energy Partners – TIR, LLC, Tulsa Inspection Resources, LLC, Mr. Charles C. Stephenson, Jr., Ms. Cynthia Field, Mr. G. Les Austin and Mr. Richard Carson (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on January 27, 2014)
10.2†	Cypress Energy Partners, L.P. 2013 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed on January 27, 2014)
10.3	Omnibus Agreement dated as of January 21, 2014, by and among Cypress Energy Partners, L.P., Cypress Energy Holdings, LLC, Cypress Energy Management, LLC, Cypress Energy Partners, LLC, Cypress Energy Partners GP, LLC, Cypress Energy Partners – TIR, LLC, Foley Inspection Services ULC, Tulsa Inspection Resources, LLC, Tulsa Inspection Resources – Canada ULC, Tulsa Inspection Resources Holdings, LLC, Tulsa Inspection Resources – Nondestructive Examination, LLC, Charles C. Stephenson, Jr. and Cynthia Field (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed on January 27, 2014)
10.4†	Form of Cypress Energy Partners, L.P. 2013 Long-Term Incentive Plan Phantom Unit Agreement (incorporated by reference to Exhibit 10.4 of our Registration Statement on Form S-1/A filed on December 17, 2013)
10.5	Credit Agreement, dated as of December 24, 2013 between Cypress, as borrower, certain of its affiliates as co-borrowers and guarantors, Deutsche Bank AG, New York Branch, as a lender, swing line lender and collateral agent, the other lenders from time to time party thereto, and Deutsche Bank Trust Company Americas, as the administrative agent (incorporated by reference to Exhibit 10.5 of our Registration Statement on Form S-1/A filed on January 10, 2014)
10.6	Amendment No. 1 to Credit Agreement, dated as of October 21, 2014 between Cypress, as borrower, certain of its affiliates as co-borrowers and guarantors, Deutsche Bank AG, New York Branch, as collateral agent, lender, issuing bank and swing line lender, the other lenders from time to time party thereto, and Deutsche Bank Trust Company Americas, as the administrative agent (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on October 24, 2014)
21.1	List of Subsidiaries of Cypress Energy Partners, L.P. (incorporated by reference to Exhibit 21.2 of our Annual Report on Form 10-K filed on March 31, 2014)
23.1*	Consent of Ernst & Young LLP
31.1*	Chief Executive Officer Certification Pursuant to Exchange Act Rule 13a-14(a) or Rule 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	

	Chief Financial Officer Certification Pursuant to Exchange Act Rule 13a-14(a) or Rule 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Chief Executive Officer Certification Pursuant to Exchange Act Rule 13a-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code, as Adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.1**	Chief Financial Officer Certification Pursuant to Exchange Act Rule 13a-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code, as Adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101 INS*	XBRL Instance Document
101 SCH*	XBRL Schema Document
101 CAL*	XBRL Calculation Linkbase Document
101 DEF*	XBRL Definition Linkbase Document
101 LAB*	XBRL Label Linkbase Document
101 PRE*	XBRL Presentation Linkbase Document

*Filed herewith.
**Furnished herewith.
†Management contract or compensatory plan or arrangement.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Tulsa, State of Oklahoma, on March 30, 2015.

Cypress Energy Partners, L.P.

By: Cypress Energy Partners GP, LLC, its general partner

/s/ G. Les Austin
By: G. Les Austin
Title: Chief Financial Officer

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

Signature	Title	Date
/ s/ Peter C. Boylan III Peter C. Boylan III	Chief Executive Officer and Chairman of the Board	March 30, 2015
/ s/ G. Les Austin G. Les Austin	Chief Financial Officer and Treasurer (Principal Financial Officer and Principal Accounting Officer)	March 30, 2015
/ s/ Henry Cornell Henry Cornell	Director	March 30, 2015
/ s/ Philip Gisi Philip Gisi	Director	March 30, 2015
/ s/ Stanley Lybarger Stanley Lybarger	Director	March 30, 2015
/ s/ John T. McNabb II John T. McNabb II	Director	March 30, 2015
/ s/ Charles C. Stephenson, Jr. Charles C. Stephenson, Jr.	Director	March 30, 2015