PATTERSON UTI ENERGY INC
Form 10-K
February 20, 2018

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, 2017

or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number 0-22664

Patterson-UTI Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware	75-2504748
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

10713 W. Sam Houston Pkwy N, Suite 800, Houston, Texas	77064
(Address of principal executive offices)	(Zip Code)

Registrant’s telephone number, including area code:

(281) 765-7100

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

Title of Each Class	Name of Exchange on Which Registered
Common Stock, $0.01 Par Value	The Nasdaq Global Select Market

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

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes or 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 or 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 Website, 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 or 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 registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes No

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $4.2 billion, calculated by reference to the closing price of $20.19 for the common stock on the Nasdaq

Global Select Market on that date.

As of February 16, 2018, the registrant had outstanding 222,286,372 shares of common stock, $0.01 par value, its only class of common stock.

Documents incorporated by reference:

Portions of the registrant's definitive proxy statement for the 2018 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this "Report") and other public filings and press releases by us contain "forward-looking statements" within the meaning of the Securities Act of 1933, as amended (the "Securities Act"), the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the Private Securities Litigation Reform Act of 1995, as amended. These forward-looking statements involve risk and uncertainty. These forward-looking statements include, without limitation, statements relating to: liquidity; revenue and cost expectations and backlog; financing of operations; oil and natural gas prices; rig counts; source and sufficiency of funds required for building new equipment, upgrading existing equipment and additional acquisitions (if opportunities arise); impact of inflation; demand for our services; competition; equipment availability; government regulation; debt service obligations; and other matters. Our forward-looking statements can be identified by the fact that they do not relate strictly to historical or current facts and often use words such as "anticipate," "believe," "budgeted," "continue," "could," "estimate," "expect," "intend," "may," "plan, "potential," "project," "pursue," "should," "strategy," "target," or "will," or the negative thereof and other words and expressio similar meaning. The forward-looking statements are based on certain assumptions and analyses we make in light of our experience and our perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances.

On April 20, 2017, we completed our merger with Seventy Seven Energy Inc. ("SSE"), pursuant to which a subsidiary of ours was merged with and into SSE, with SSE continuing as the surviving entity and one of our wholly owned subsidiaries (the "SSE merger"). On October 11, 2017, we completed our acquisition of MS Directional, LLC (f/k/a Multi-Shot, LLC) ("MS Directional"). These forward-looking statements include, without limitation, our expectations with respect to:

- synergies, costs and other anticipated financial impacts of the SSE merger and the MS Directional acquisition;
- future financial and operating results of the combined company; and
- the combined company's plans, objectives, expectations and intentions with respect to future operations and services.

Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. These forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from actual future results expressed or implied by the forward-looking statements. These risks and uncertainties also include those set forth under "Risk Factors" contained in Item 1A of this Report and in Management's Discussion and Analysis of Financial Condition and Results of Operations included in this Report and other sections of our filings with the United States Securities and Exchange Commission (the "SEC") under the Exchange Act and the Securities Act, as well as, among others, risks and uncertainties relating to:

- the diversion of management time on merger-related issues;
- the ultimate timing, outcome and results of integrating our operations with those of SSE and MS Directional;
- the effects of our business combination with SSE and MS Directional, including the combined company's future financial condition, results of operations, strategy and plans;
- potential adverse reactions or changes to business relationships resulting from the SSE merger and MS Directional acquisition;
- expected benefits from the SSE merger and MS Directional acquisition and our ability to realize those benefits;
- the results of merger-related litigation, settlements and investigations;
- availability of capital and the ability to repay indebtedness when due;
- volatility in customer spending and in oil and natural gas prices that could adversely affect demand for our services and their associated effect on rates;
- loss of key customers;
- utilization, margins and planned capital expenditures;
- synergies, costs and financial and operating impacts of acquisitions;

- interest rate volatility;
- compliance with covenants under our debt agreements;
- excess availability of land drilling rigs, pressure pumping and directional drilling equipment, including as a result of reactivation, improvement or construction;
- specialization of methods, equipment and services and new technologies;

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- operating hazards attendant to the oil and natural gas business;
- failure by customers to pay or satisfy their contractual obligations (particularly with respect to fixed-term contracts);
- difficulty in building and deploying new equipment;
- expansion and development trends of the oil and natural gas industry;
- weather;
- shortages, delays in delivery, and interruptions in supply, of equipment and materials;
- the ability to retain management and field personnel;
- the ability to effectively identify and enter new markets;
- the ability to realize backlog;
- strength and financial resources of competitors;
- environmental risks and ability to satisfy future environmental costs;
- global economic conditions;
- adverse oil and natural gas industry conditions;
- adverse credit and equity market conditions;
- operating costs;
- competition and demand for our services;
- liabilities from operational risks for which we do not have and receive full indemnification or insurance;
- governmental regulation;
- ability to obtain insurance coverage on commercially reasonable terms;
- financial flexibility;
- legal proceedings and actions by governmental or other regulatory agencies;
- technology-related disputes; and
- other financial, operational and legal risks and uncertainties detailed from time to time in our SEC filings.

We caution that the foregoing list of factors is not exhaustive. Additional information concerning these and other risk factors is contained in this Report and may be contained in our future filings with the SEC. You are cautioned not to place undue reliance on any of our forward-looking statements. The forward-looking statements speak only as of the date made and, other than as required by law, we undertake no obligation to update publicly or revise any of these forward-looking statements, whether as a result of new information, future events or otherwise. In the event that we update any forward-looking statement, no inference should be made that we will make additional updates with respect to that statement, related matters or any other forward-looking statements. All subsequent written and oral forward-looking statements concerning us or other matters and attributable to us or any person acting on our behalf are expressly qualified in their entirety by the cautionary statements above.

PART I

Item 1. Business

Available Information

This Report, along with our 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 Exchange Act, are available free of charge through our internet website (www.patenergy.com) as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The information contained on our website is not part of this Report or other filings that we make with the SEC. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Overview

We are a Houston, Texas-based oilfield services company that primarily owns and operates in the United States one of the largest fleets of land-based drilling rigs and a large fleet of pressure pumping equipment. We were formed in 1978 and reincorporated in 1993 as a Delaware corporation.

Our contract drilling business operates in the continental United States and western Canada, and we are pursuing contract drilling opportunities outside of North America. As of December 31, 2017, we had a drilling fleet that consisted of 295 marketed land-based drilling rigs. A drilling rig includes the structure, power source and machinery necessary to cause a drill bit to penetrate the earth to a depth desired by the customer. We also have a substantial inventory of drill pipe and drilling rig components that support our drilling operations.

We provide pressure pumping services to oil and natural gas operators primarily in Texas and the Mid-Continent and Appalachian regions. Pressure pumping services consist primarily of well stimulation services (such as hydraulic fracturing) and cementing services for completion of new wells and remedial work on existing wells. As of December 31, 2017, we had approximately 1.6 million fracturing horsepower to provide these services. Our pressure pumping operations are supported by a fleet of other equipment, including blenders, tractors, manifold trailers and numerous trailers for transportation of materials to and from the worksite as well as bins for storage of materials at the worksite.

We also provide a comprehensive suite of directional drilling services in most major producing onshore oil and gas basins in the United States. Our directional drilling services include directional drilling, downhole performance motors, directional surveying, measurement-while-drilling, and wireline steering tools.

We have other operations where we provide oilfield rental equipment in many of the major producing onshore oil and gas basins in the United States, and we also manufacture and sell pipe handling components and related technology to drilling contractors in North America and other select markets. In addition, we own and invest, as a non-operating working interest owner, in oil and natural gas assets that are primarily located in Texas and New Mexico.

Recent Developments

On January 19, 2018, we completed an offering of $525 million aggregate principal amount of our 3.95% Senior Notes due 2028 (the “2028 Notes”) initially guaranteed on a senior unsecured basis by certain of our subsidiaries. The net proceeds before offering expenses were approximately $521 million, of which we used $239 million to repay amounts outstanding under our revolving credit facility. We intend to use the remainder of the net proceeds for general corporate purposes.

On October 11, 2017, we acquired all of the issued and outstanding limited liability company interests of MS Directional. The aggregate consideration paid by us consisted of $69.8 million in cash and approximately 8.8 million shares of our common stock. Based on the closing price of our common stock on the closing date of the transaction, the total fair value of the consideration transferred to effect the acquisition of MS Directional was approximately $257 million.

On December 12, 2016, we entered into an Agreement and Plan of Merger (the "merger agreement") with SSE. On April 20, 2017, pursuant to the merger agreement, a subsidiary of ours was merged with and into SSE, with SSE continuing as the surviving entity and one of our wholly-owned subsidiaries. Pursuant to the terms of the merger agreement, we acquired all of the issued and outstanding shares of common stock of SSE, in exchange for approximately 46.3 million shares of our common stock. Concurrent with the closing of the merger, we repaid all of the outstanding debt of SSE totaling $472 million. Based on the closing price of our common stock on April 20, 2017, the total fair value of the consideration transferred to effect the acquisition of SSE was approximately $1.5 billion. On April 20, 2017, following the SSE merger, SSE was merged with and into our newly-formed subsidiary named Seventy Seven Energy LLC ("SSE LLC"), with SSE LLC continuing as the surviving entity and one of our wholly-owned subsidiaries.

Through the SSE merger, we acquired a fleet of 91 drilling rigs, 36 of which we consider to be APEX® rigs. Additionally, through the SSE merger, we acquired approximately 500,000 horsepower of modern, efficient fracturing equipment located in Oklahoma and Texas. The oilfield rentals business acquired through the SSE merger has a modern, well-maintained fleet of premium oilfield rental tools, and provides specialized services for land-based oil and natural gas drilling, completion and workover activities.

Operational data in the discussion and analysis in this Report includes the results of operations of the MS Directional business since October 11, 2017 and the results of operations of the SSE businesses since April 20, 2017.

Quarterly average oil prices and our quarterly average number of rigs operating in the United States for 2015, 2016 and 2017 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2015:				
Average oil price per Bbl (1)	$48.54	$57.85	$46.42	$41.96
Average rigs operating per day - U.S. (2)	165	122	105	88
2016:				
Average oil price per Bbl (1)	$33.18	$45.41	$44.85	$49.15
Average rigs operating per day - U.S. (2)	71	55	60	66
2017:				
Average oil price per Bbl (1)	$51.77	$48.24	$48.16	$55.37
Average rigs operating per day - U.S. (2)	81	145	159	159

(1) The average oil price represents the average monthly WTI spot price as reported by the United States Energy Information Administration.
(2) A rig is considered to be operating if it is earning revenue pursuant to a contract on a given day.

The closing price of oil was as high as $107.95 per barrel in June 2014. Prices began to fall in the third quarter of 2014 and reached a twelve-year low of $26.19 in February 2016. Oil and natural gas prices have modestly recovered from the lows experienced in the first quarter of 2016. Oil prices averaged $55.37 per barrel in the fourth quarter of 2017.

Our rig count in the United States declined significantly during the industry downturn that began in late 2014, but has improved since the second quarter of 2016. Our average rig count in the United States was 159 rigs for both the third and fourth quarter of 2017, with the third quarter of 2017 being the first quarter with a full quarter contribution from the rigs acquired in the SSE merger. Our rig count in the United States at December 31, 2017 was 163 rigs. Term contracts have supported our operating rig count during the last three years. Based on contracts currently in place, we expect an average of 96 rigs operating under term contracts during the first quarter of 2018 and an average of 67 rigs operating under term contracts throughout 2018.

Activity levels in our pressure pumping business also improved during 2017, especially in the Permian Basin. We reactivated two frac spreads during the third quarter and one additional frac spread during the fourth quarter. With the addition of these three frac spreads, we exited 2017 with 23 active frac spreads or approximately 1.25 million active fracturing horsepower.

Industry Segments

Our revenues, operating income (loss) and identifiable assets are primarily attributable to two industry segments:

- contract drilling services, and
- pressure pumping services.

Our contract drilling services industry segment had operating losses in 2017, 2016 and 2015. Our pressure pumping services industry segment had operating income in 2017 and operating losses in 2016 and 2015. Our third industry segment, directional drilling services, is a new segment for us as a result of the MS Directional acquisition and accounted for approximately two percent of our 2017 consolidated revenues.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 14 of Notes to Consolidated Financial Statements included as a part of Items 7 and 8, respectively, of this Report for financial information pertaining to these industry segments.

Contract Drilling Operations

General — We market our contract drilling services to major, independent and other oil and natural gas operators. As of December 31, 2017, we had 295 marketed land-based drilling rigs based in the following regions:

- 71 in west Texas and southeastern New Mexico,
- 32 in north central and east Texas and northern Louisiana,
- 42 in the Rocky Mountain region (Colorado, Wyoming and North Dakota),
- 40 in south Texas,
- 55 in western Oklahoma,
- 48 in the Appalachian region (Pennsylvania, Ohio and West Virginia), and
- 7 in western Canada.

Our marketed drilling rigs have rated maximum depth capabilities ranging from approximately 13,200 feet to 25,000 feet. All of these drilling rigs are electric rigs. An electric rig converts the power from its diesel engines into electricity to power the rig. We also have a substantial inventory of drill pipe and drilling rig components, which may be used in the activation of additional drilling rigs or as upgrades or replacement parts for marketed rigs.

Drilling rigs are typically equipped with engines, drawworks, top drives, masts, pumps to circulate the drilling fluid, blowout preventers, drill pipe and other related equipment. Over time, components on a drilling rig are replaced or rebuilt. We spend significant funds each year as part of a program to modify, upgrade and maintain our drilling rigs. We have spent approximately $954 million during the last three years on capital expenditures to (1) build new land drilling rigs and (2) modify, upgrade and extend the lives of components of our drilling fleet. During fiscal years 2017, 2016 and 2015, we spent approximately $354 million, $73 million and $527 million, respectively, on these capital expenditures.

Depth and complexity of the well, drill site conditions and the number of wells to be drilled on a pad are the principal factors in determining the specifications of the rig selected for a particular job.

Our contract drilling operations depend on the availability of drill pipe, drill bits, replacement parts and other related rig equipment, fuel and other materials and qualified personnel. Some of these have been in short supply from time to time.

Drilling Contracts — Most of our drilling contracts are with established customers on a competitive bid or negotiated basis. Our bid for each job depends upon location, equipment to be used, estimated risks involved, estimated duration of the job, availability of drilling rigs and other factors particular to each proposed contract. Our drilling contracts are either on a well-to-well basis or a term basis. Well-to-well contracts are generally short-term in nature and cover the drilling of a single well or a series of wells. Term contracts are entered into for a specified period of time (frequently six months to two years) and provide for the use of the drilling rig to drill multiple wells. During 2017, our average number of days to drill a well (which includes moving to the drill site, rigging up and rigging down) was approximately 15 days.

Our drilling contracts obligate us to provide and operate a drilling rig and to pay certain operating expenses, including wages of our drilling personnel and necessary maintenance expenses. Most drilling contracts are subject to termination by the customer on short notice and may or may not contain provisions for an early termination payment to us in the event that the contract is terminated by the customer.

Our drilling contracts provide for payment on a daywork basis. Under daywork contracts, we provide the drilling rig and crew to the customer. The customer provides the program for the drilling of the well. Our compensation is based on a contracted rate per day during the period the drilling rig is utilized. We often receive a lower rate when the drilling rig is moving or when drilling operations are interrupted or restricted by adverse weather conditions or other conditions beyond our control. Daywork contracts typically provide separately for mobilization of the drilling rig. All of the wells we drilled in 2017, 2016 and 2015 were under daywork contracts.

From time to time more than five years ago, we contracted to drill some wells to a certain depth under specified conditions for a fixed price per foot (on a footage basis) or for a fixed fee (on a turnkey basis). We generally assume greater operational and economic risk drilling on a turnkey basis than on a footage basis and greater operational and economic risk drilling on a footage basis than on a daywork basis.

Contract Drilling Activity — Information regarding our contract drilling activity for the last three years follows:

	Year Ended December 31,		
	2017	2016	2015
Average rigs operating per day - U.S.(1)	136	63	120
Average rigs operating per day - Canada(1)	2	2	4
Number of rigs operated during the year	179	100	223
Number of wells drilled during the year	3,160	1,470	2,448
Number of operating days	50,427	23,596	45,142

(1) A rig is considered to be operating if it is earning revenue pursuant to a contract on a given day.

Drilling Rigs and Related Equipment — We have made significant upgrades during the last several years to our drilling fleet to match the needs of our customers. While conventional wells remain a source of oil and natural gas, our customers have expanded the development of shale and other unconventional wells to help supply the long-term demand for oil and natural gas in North America.

To address our customers' needs for drilling horizontal wells in shale and other unconventional resource plays, we have expanded our areas of operation and improved the capability of our drilling fleet. We have delivered new APEX® rigs to the market and have made performance and safety improvements to existing high capacity rigs. APEX® rigs are electric rigs with advanced electronic drilling systems, 500 ton top drives, iron roughnecks, hydraulic catwalks, and other automated pipe handling equipment. APEX® rigs that are pad capable are designed to efficiently drill multiple wells from a single pad, by "walking" between the wellbores without requiring time to lower the mast and lay down the drill pipe. As of December 31, 2017, our marketed land-based drilling fleet was comprised of the following:

	Number of Rigs			
Classification	United States	Canada	Total	Percent Pad Capable
APEX® 1500 HP rigs	164	1	165	86 %
APEX® 1000 HP rigs	20	—	20	100 %
APEX® 1200 HP rigs	4	—	4	100 %
APEX® 1400 HP rigs	5	—	5	100 %
APEX® 2000 HP rigs	5	—	5	60 %
Other electric rigs	90	6	96	49 %
Total	288	7	295	75 %
Average horsepower	1,394	1,171	1,389	

The U.S. land rig industry has recently begun referring to certain high specification rigs as “super-spec” rigs. We consider a super-spec rig to be a 1,500 horsepower, AC powered rig that has a 750,000 pound hookload, has a 7,500 psi circulating system and is pad capable. We currently estimate there are approximately 550 super-spec rigs in the United States, which includes 130 of our APEX® rigs.

We perform repair and/or overhaul work to our drilling rig equipment at our yard facilities located in Texas, Oklahoma, Wyoming, Colorado, North Dakota, Pennsylvania and western Canada.

Pressure Pumping Operations

General — We provide pressure pumping services to oil and natural gas operators primarily in Texas (West and South Regions) and the Mid-Continent (Mid-Con Region) and Appalachian regions (Northeast Region). Pressure pumping services consist of well stimulation services (such as hydraulic fracturing) and cementing services for the completion of new wells and remedial work on existing wells. Wells drilled in shale formations and other unconventional plays require well stimulation through hydraulic fracturing to allow the flow of oil and natural gas. This is accomplished by pumping fluids under pressure into the well bore to fracture the formation. Many wells in conventional plays also receive well stimulation services. The cementing process inserts material between the wall of the well bore and the casing to support and stabilize the casing.

Pressure Pumping Contracts – Our pressure pumping operations are conducted pursuant to a work order for a specific job or pursuant to a term contract. The term contracts are generally entered into for a specified period of time and may include minimum revenue, usage or stage requirements. We are compensated based on a combination of charges for equipment, personnel, materials, mobilization and other items.

Equipment — We have pressure pumping equipment used in providing hydraulic fracturing services as well as nitrogen, cementing and acid pumping services, with a total of approximately 1.6 million horsepower as of December 31, 2017. Pressure pumping equipment at December 31, 2017 included:

	Fracturing Equipment	Other Pumping Equipment	Total
West Texas Region			
Number of units	235	30	265
Approximate horsepower	537,950	30,890	568,840
South Texas Region			
Number of units	147	—	147
Approximate horsepower	361,250	—	361,250
Mid-Con Region			
Number of units	134	—	134
Approximate horsepower	305,500	—	305,500
Northeast Region			
Number of units	169	95	264
Approximate horsepower	353,800	55,400	409,200
Combined:			
Number of units	685	125	810
Approximate horsepower	1,558,500	86,290	1,644,790

Our pressure pumping operations are supported by a fleet of other equipment including blenders, tractors, manifold trailers and numerous trailers for transportation of materials to and from the worksite as well as bins for storage of materials at the worksite.

Materials – Our pressure pumping operations require the use of acids, chemicals, proppants, fluid supplies and other materials, any of which can be in short supply, including severe shortages, from time to time. We purchase these materials from various suppliers. These purchases are made in the spot market or pursuant to other arrangements that do not cover all of our required supply and sometimes require us to purchase the supply or pay liquidated damages if we do not purchase the material. Given the limited number of suppliers of certain of our materials, we may not always be able to make alternative arrangements if we are unable to reach an agreement with a supplier for delivery of any particular material, or should one of our suppliers fail to timely deliver our materials.

Directional Drilling Operations

General – We generally utilize our own proprietary downhole motors and equipment to provide a comprehensive suite of directional drilling services, including directional drilling, downhole performance motors, directional surveying, measurement while drilling (“MWD”), and wireline steering tools, in most major onshore oil and natural gas basins in the United States. We generally design, manufacture and maintain our own fleet of downhole drilling motors and MWD equipment. We occasionally rent motors and equipment from third parties during periods in which we experience shortages from our vendors, which can occur during periods of increased industry activity. As a complement to our core directional drilling services, we provide downhole survey services and rent our proprietary drilling motors to both oil and natural gas operators and other oilfield service companies. Our customers primarily consist of major integrated energy companies and large North American independent oil and natural gas operators. We believe our customers use our services because of the quality of our specialized, technology-driven equipment and our well-trained and experienced workforce, which enable us to provide our customers with high-quality, reliable and safe directional drilling services. We utilize our fleet of directional drilling motors, MWD equipment and survey equipment to provide: (1) directional drilling services, (2) third-party motor rentals and (3) downhole survey services.

Directional Drilling Services – We provide our directional drilling services on a day-rate basis, typically under master service agreements. Revenue from directional drilling services is recognized as work progresses based on the number of days of work completed. Our day rates and other charges generally vary by location and depend on the equipment and personnel required for the job and market conditions in the region in which the services are performed. In addition to rates that are charged during periods of active directional drilling, a stand-by rate is typically agreed upon in advance and charged on a daily basis during periods when drilling is temporarily suspended while other on-site activity is conducted at the direction of the operator or another service provider.

Third-Party Motor Rental – We rent our drilling motors on an hourly- or day-rate basis to complement our directional drilling services and optimize the utilization of our asset base. Our third-party motor rental revenue is recognized as work progresses based on the number of days or hours our motors are used or are on location.

Downhole Survey Services – We provide our downhole survey services on a day-rate, hourly-rate or completed-job basis. Revenue for our downhole survey services is recognized upon the completion of each day's work. Our downhole survey services are typically non-contractual. We normally provide a quote to our customers in advance and then issue an invoice for the downhole survey services provided based on a completed field ticket.

Equipment – We generally design, manufacture, maintain and inspect our own equipment. We occasionally rent motors and equipment from third parties during periods in which we experience shortages from our vendors, which can occur during periods of increased industry activity. We have developed proprietary equipment for our drilling motors, mud pulse and electromagnetic data transfer MWD equipment and survey tools. We believe that our vertical integration strategy allows us to deliver better operational performance and higher equipment reliability to our customers. Vertical integration also allows us to build our tools more efficiently and at a lower cost than if purchased from third parties. In addition, we have the ability to upgrade our tools in response to market conditions or our customers' job requirements, which allows us to minimize the costs and delays associated with sending equipment to original manufacturers. Our internal maintenance capability also affords us enhanced control over our supply chain and increases the effective utilization of our assets. As of December 31, 2017, we had a comprehensive fleet of over 1,600 motors that serve both internal needs and external motor rental requirements. In addition to our motor fleet, we had 112 MWD systems as well as downhole surveying equipment to provide accurate wellbore surveys.

Oilfield Rentals

Our oilfield rentals business has a modern, well-maintained fleet of premium oilfield rental tools, and provides specialized services for land-based oil and natural gas drilling, completion and workover activities. We offer an extensive line of rental tools, including a full line of tubular products specifically designed for horizontal drilling and completion, with high-torque, premium-connection drill pipe, drill collars and tubing. Additionally, we offer surface rental equipment including blowout preventers, frac tanks, mud tanks and environmental containment that encompass all phases of the hydrocarbon extraction and production process. Our air drilling equipment and services enable extraction in select basins where certain segments of formations preclude the use of drilling fluid, permitting operators to drill through problematic zones without the risk of fluid absorption and damage to the wellbore. We also provide frac-support services, including delivery of on-site frac water through a water transfer operation using innovative lay-flat pipe, and monitoring and controlling of production returns. We offer oilfield rental services in many of the major producing onshore oil and gas basins in the United States. We price our rentals and services based on the type of equipment being rented and the services being performed. Substantially all rental revenue we earn is based upon a charge for the actual period of time the rental is provided to our customer on a market-based, fixed per-day or per-hour fee.

Contracts

We believe that our contract drilling, pressure pumping, directional drilling and oilfield rentals contracts generally provide for indemnification rights and obligations that are customary for the markets in which we conduct those operations. However, each contract contains the actual terms setting forth our rights and obligations and those of the customer, any of which rights and obligations may deviate from what is customary due to particular industry conditions, customer requirements, applicable law or other factors.

Customers

Our customer base includes major, independent and other oil and natural gas operators. With respect to our consolidated operating revenues in 2017, we received approximately 43% from our ten largest customers and approximately 29% from our five largest customers. During 2017, no customer accounted for more than 10% of our consolidated operating revenues. The loss of, or reduction in business from, one or more of our larger customers could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Backlog

Our contract drilling backlog as of December 31, 2017 and 2016 was $544 million and $417 million, respectively. Approximately 19% of the total contract drilling backlog at December 31, 2017 is reasonably expected to remain after 2018. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations” included as a part of Item 7 of this Report for information pertaining to backlog.

Competition

The businesses in which we operate are highly competitive. Historically, available equipment used in these businesses has frequently exceeded demand, particularly in an industry downturn, such as the current market environment. The price for our services is a key competitive factor, in part because equipment used in our businesses can be moved from one area to another in response to market conditions. In addition to price, we believe availability, condition and technical specifications of equipment, quality of personnel, service quality and safety record are key factors in determining which contractor is awarded a job. We expect that the market for our services will continue to be highly competitive.

Government and Environmental Regulation

All of our operations and facilities are subject to numerous federal, state, foreign, regional and local laws, rules and regulations related to various aspects of our business, including:

- drilling of oil and natural gas wells,
- hydraulic fracturing, cementing, nitrogen and acidizing and related well servicing activities,
- directional drilling services, third-party motor rentals and downhole survey services,
- containment and disposal of hazardous materials, oilfield waste, other waste materials and acids,
- use of underground storage tanks and injection wells, and
- our employees.

To date, applicable environmental laws and regulations in the places in which we operate have not required the expenditure of significant resources outside the ordinary course of business. We do not anticipate any material capital expenditures for environmental control facilities or extraordinary expenditures to comply with environmental rules and regulations in the foreseeable future. However, compliance costs under existing laws or under any new requirements could become material, and we could incur liability in any instance of noncompliance.

Our business is generally affected by political developments and by federal, state, foreign, regional and local laws, rules and regulations that relate to the oil and natural gas industry. The adoption of laws, rules and regulations affecting the oil and natural gas industry for economic, environmental and other policy reasons could increase costs relating to drilling, completion and production, and otherwise have an adverse effect on our operations. Federal, state, foreign, regional and local environmental laws, rules and regulations currently apply to our operations and may become more stringent in the future. Any limitation, suspension or moratorium of the services we or others provide, whether or not short-term in nature, by a federal, state, foreign, regional or local governmental authority, could have a material adverse effect on our business, financial condition and results of operations.

We believe we use operating and disposal practices that are standard in the industry. However, hydrocarbons and other materials may have been disposed of, or released in or under properties currently or formerly owned or operated by us or our predecessors, which may have resulted, or may result, in soil and groundwater contamination in certain locations. Any contamination found on, under or originating from the properties may be subject to remediation requirements under federal, state, foreign, regional and local laws, rules and regulations. In addition, some of these properties have been operated by third parties over whom we have no control of their treatment of hydrocarbon and other materials or the manner in which they may have disposed of or released such materials. We could be required to remove or remediate wastes disposed of or released by prior owners or operators. In addition, it is possible we could be held responsible for oil and natural gas properties in which we own an interest but are not the operator.

Some of the environmental laws and regulations that are applicable to our business operations are discussed in the following paragraphs, but the discussion does not cover all environmental laws and regulations that govern our operations.

In the United States, the Federal Comprehensive Environmental Response Compensation and Liability Act of 1980, as amended, commonly known as CERCLA, and comparable state statutes impose strict liability on:

- owners and operators of sites, including prior owners and operators who are no longer active at a site; and
- persons who disposed of or arranged for the disposal of “hazardous substances” found at sites.

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The Federal Resource Conservation and Recovery Act ("RCRA"), as amended, and comparable state statutes and implementing regulations govern the disposal of "hazardous wastes." Although CERCLA currently excludes petroleum from the definition of "hazardous substances," and RCRA also excludes certain classes of exploration and production wastes from regulation, such exemptions by Congress under both CERCLA and RCRA may be deleted, limited, or modified in the future. For example, in December 2016, the U.S. Environmental Protection Agency ("EPA") and environmental groups entered into a consent decree to address the EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking by March 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. If changes are made to the classification of exploration and production wastes under CERCLA and/or RCRA, we could be required to remove and remediate previously disposed of materials (including materials disposed of or released by prior owners or operators) from properties (including ground water contaminated with hydrocarbons) and to perform removal or remedial actions to prevent future contamination.

The Federal Water Pollution Control Act and the Oil Pollution Act of 1990, each as amended, and implementing regulations govern:

- the prevention of discharges, including oil and produced water spills, into jurisdictional waters; and
- liability for drainage into such waters.

The Oil Pollution Act imposes strict liability for a comprehensive and expansive list of damages from an oil spill into jurisdictional waters from facilities. Liability may be imposed for oil removal costs and a variety of public and private damages. Penalties may also be imposed for violation of federal safety, construction and operating regulations, and for failure to report a spill or to cooperate fully in a clean-up.

The Oil Pollution Act also expands the authority and capability of the federal government to direct and manage oil spill clean-up and operations, and requires operators to prepare oil spill response plans in cases where it can reasonably be expected that substantial harm will be done to the environment by discharges on or into navigable waters. Failure to comply with ongoing requirements or inadequate cooperation during a spill event may subject a responsible party, such as us, to civil or criminal actions. Although the liability for owners and operators is the same under the Federal Water Pollution Act, the damages recoverable under the Oil Pollution Act are potentially much greater and can include natural resource damages.

The U.S. Occupational Safety and Health Administration ("OSHA") promulgates and enforces laws and regulations governing the protection of the health and safety of employees. The OSHA hazard communication standard, EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governments and citizens. Also, OSHA has established a variety of standards related to workplace exposure to hazardous substances and employee health and safety.

Our activities include the performance of hydraulic fracturing services to enhance the production of oil and natural gas from formations with low permeability, such as shale and other unconventional formations. Due to concerns raised relating to potential impacts of hydraulic fracturing, including on groundwater quality and seismic activity, legislative and regulatory efforts at the federal level and in some state and local jurisdictions have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or prohibit the activity altogether. Such efforts could have an adverse effect on oil and natural gas production activities, which in turn could have an adverse effect on the hydraulic fracturing services that we render for our exploration and production customers. See "Item 1A. Risk Factors – Potential Legislation and Regulation Covering Hydraulic Fracturing or Other Aspects of the Oil and Gas Industry Could Increase Our Costs and Limit or Delay Our Operations."

In Canada, a variety of federal, provincial and municipal laws, rules and regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and wastes and in connection with spills, releases and emissions of various substances to the environment. Other jurisdictions where we may conduct operations have similar environmental and regulatory regimes with which we would be required to comply. These laws, rules and regulations also require that facility sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, new projects or changes to existing projects may require the submission and approval of environmental assessments or permit applications. These laws, rules and regulations are subject to frequent change, and the clear trend is to place increasingly stringent limitations on activities that may affect the environment.

Our operations are also subject to federal, state, foreign, regional and local laws, rules and regulations for the control of air emissions, including those associated with the Federal Clean Air Act and the Canadian Environmental Protection Act. We and our customers may be required to make capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. For more information, please refer to our discussion under “Item 1A. Risk Factors – Environmental and Occupational Health and Safety Laws and Regulations, Including Violations Thereof, Could Materially Adversely Affect Our Operating Results.”

We are aware of the increasing focus of local, state, national and international regulatory bodies on greenhouse gas (“GHG”) emissions and climate change issues. We are also aware of legislation proposed by U.S. lawmakers and the Canadian legislature to reduce GHG emissions, as well as GHG emissions regulations enacted by the EPA and the Canadian provinces of Alberta and British Columbia. We will continue to monitor and assess any new policies, legislation or regulations in the areas where we operate to determine the impact of GHG emissions and climate change on our operations and take appropriate actions, where necessary. Any direct and indirect costs of meeting these requirements may adversely affect our business, results of operations and financial condition. See “Item 1A. Risk Factors – Legislation and Regulation of Greenhouse Gases Could Adversely Affect Our Business.”

Risks and Insurance

Our operations are subject to many hazards inherent in the businesses in which we operate, including inclement weather, blowouts, well fires, loss of well control, pollution, exposure and reservoir damage. These hazards could cause personal injury or death, work stoppage, and serious damage to equipment and other property, as well as significant environmental and reservoir damages. These risks could expose us to substantial liability for personal injury, wrongful death, property damage, loss of oil and natural gas production, pollution and other environmental damages.

We have indemnification agreements with many of our customers, and we also maintain liability and other forms of insurance. In general, our contracts typically contain provisions requiring our customers to indemnify us for, among other things, reservoir and certain pollution damage. Our right to indemnification may, however, be unenforceable or limited due to negligent or willful acts or omissions by us, our subcontractors and/or suppliers. Our customers and other third parties may dispute, or be unable to meet, their indemnification obligations to us due to financial, legal or other reasons. Accordingly, we may be unable to transfer these risks to our customers and other third parties by contract or indemnification agreements. Incurring a liability for which we are not fully indemnified or insured could have a material adverse effect on our business, financial condition, cash flows and results of operations.

We maintain insurance coverage of types and amounts that we believe to be customary in the industry, but we are not fully insured against all risks, either because insurance is not available or because of the high premium costs. The insurance coverage that we maintain includes insurance for fire, windstorm and other risks of physical loss to our equipment and certain other assets, employer’s liability, automobile liability, commercial general liability, workers’ compensation and insurance for other specific risks. We cannot assure, however, that any insurance obtained by us will be adequate to cover any losses or liabilities, or that this insurance will continue to be available or available on terms that are acceptable to us. While we carry insurance to cover physical damage to, or loss of, a substantial portion of our equipment and certain other assets, such insurance does not cover the full replacement cost of such equipment or other assets. We have also elected in some cases to accept a greater amount of risk through increased deductibles on certain insurance policies. For example, we generally maintain a $1.5 million per occurrence deductible on our workers’ compensation insurance coverage, a $1.0 million per occurrence deductible on our equipment insurance coverage, a $2.0 million per occurrence deductible on our general liability coverage and a $2.0 million per occurrence deductible on our automobile liability insurance coverage. We also self-insure a number of other risks, including loss of earnings and business interruption and cybersecurity risks, and we do not carry a significant amount of insurance to cover risks of underground reservoir damage.

Our insurance will not in all situations provide sufficient funds to protect us from all liabilities that could result from our operations. Our coverage includes aggregate policy limits and exclusions. As a result, we retain the risk for any loss in excess of these limits or that is otherwise excluded from our coverage. There can be no assurance that insurance will be available to cover any or all of our operational risks, or, even if available, that insurance premiums or other costs will not rise significantly in the future, so as to make the cost of such insurance prohibitive, or that our coverage will cover a specific loss. Further, we may experience difficulties in collecting from insurers or such insurers may deny all or a portion of our claims for insurance coverage. Incurring a liability for which we are not fully insured or indemnified could materially adversely affect our business, financial condition, cash flows and results of operations.

If a significant accident or other event occurs that is not fully covered by insurance or an enforceable and recoverable indemnity from a third party, it could have a material adverse effect on our business, financial condition, cash flows and results of operations. See "Item 1A. Risk Factors – Our Operations Are Subject to a Number of Operational Risks, Including Environmental and Weather Risks, Which Could Expose Us to Significant Losses and Damage Claims. We Are Not Fully Insured Against All of These Risks and Our Contractual Indemnity Provisions May Not Fully Protect Us."

Employees

We had approximately 8,000 full-time employees as of February 16, 2018. The number of employees fluctuates depending on the current and expected demand for our services. We consider our employee relations to be satisfactory. None of our employees are represented by a union.

Seasonality

Seasonality has not significantly affected our overall operations. However, our drilling operations in Canada are subject to slow periods of activity during the annual spring thaw. Additionally, toward the end of some years, we experience slower activity in our pressure pumping operations in connection with the holidays and as customers' capital expenditure budgets are depleted. Occasionally, our operations have been negatively impacted by severe weather conditions.

Raw Materials and Subcontractors

We use many suppliers of raw materials and services. Although these materials and services have historically been available, there is no assurance that such materials and services will continue to be available on favorable terms or at all. We also utilize numerous independent subcontractors from various trades.

Item 1A. Risk Factors.

You should consider each of the following factors as well as the other information in this Report in evaluating our business and our prospects. Additional risks and uncertainties not presently known to us or that we currently consider immaterial may also impair our business operations. If any of the following risks actually occur, our business, financial condition, cash flows and results of operations could be harmed. You should also refer to the other information set forth in this Report, including our consolidated financial statements and the related notes.

We Are Dependent on the Oil and Natural Gas Industry and Market Prices for Oil and Natural Gas. Declines in Customers' Operating and Capital Expenditures and in Oil and Natural Gas Prices May Adversely Affect Our Operating Results.

We depend on our customers' willingness to make operating and capital expenditures to explore for, develop and produce oil and natural gas in North America. When these expenditures decline, our business may suffer. Our customers' willingness to explore, develop and produce depends largely upon prevailing industry conditions that are influenced by numerous factors over which we have no control, such as:

- the supply of and demand for oil and natural gas, including current natural gas storage capacity and usage,
- the prices, and expectations about future prices, of oil and natural gas,
- the supply of and demand for drilling, pressure pumping and directional drilling services,
- the cost of exploring for, developing, producing and delivering oil and natural gas,
- the environmental, tax and other laws and governmental regulations regarding the exploration, development, production and delivery of oil and natural gas, and in particular, public pressure on, and legislative and regulatory interest within, federal, state, foreign, regional and local governments to stop, significantly limit or regulate drilling and pressure pumping activities, including hydraulic fracturing, and
- merger and divestiture activity among oil and natural gas producers.

In particular, our revenue, profitability and cash flows are highly dependent upon prevailing prices for oil and natural gas and expectations about future prices. For many years, oil and natural gas prices and markets have been extremely volatile. Prices, and expectations about future prices, are affected by factors such as:

- market supply and demand,
- the desire and ability of the Organization of Petroleum Exporting Countries ("OPEC") to set and maintain production and price targets,
- the level of production by OPEC and non-OPEC countries,
- domestic and international military, political, economic and weather conditions,
- legal and other limitations or restrictions on exportation and/or importation of oil and natural gas,
- technical advances affecting energy consumption and production, and

- the price and availability of alternative fuels.

All of these factors are beyond our control. The closing price of oil was as high as $107.95 per barrel in June 2014. Prices began to fall in the third quarter of 2014 and reached a twelve-year low of $26.19 in February 2016. As a result of the lower level of oil prices, our industry has experienced a severe decline in both contract drilling and pressure pumping activity levels. While oil and natural gas prices modestly recovered since the first quarter of 2016, and we have experienced an increase in the demand for our services since 2016, our average number of rigs operating remains well below the number of our available rigs, and a portion of our pressure pumping horsepower remains stacked.

We expect oil and natural gas prices to continue to be volatile and to affect our financial condition, operations and ability to access sources of capital. Higher oil and natural gas prices do not necessarily result in increased activity because demand for our services is generally driven by our customers' expectations of future oil and natural gas prices. A decline in demand for oil and natural gas, prolonged low oil or natural gas prices or expectations of decreases in oil and natural gas prices, would likely result in reduced capital expenditures by our customers and decreased demand for our services, which could have a material adverse effect on our operating results, financial condition and cash flows. Even during periods of high prices for oil and natural gas, companies exploring for oil and natural gas may cancel or curtail programs, or reduce their levels of capital expenditures for exploration and production for a variety of reasons, which could reduce demand for our services.

Global Economic Conditions May Adversely Affect Our Operating Results.

Global economic conditions and volatility in commodity prices may cause our customers to reduce or curtail their drilling and well completion programs, which could result in a decrease in demand for our services. In addition, uncertainty in the capital markets, whether due to global economic conditions, low commodity prices or otherwise may result in reduced access to, or an inability to obtain, financing by us, our customers and our suppliers and result in reduced demand for our services. Furthermore, these factors may result in certain of our customers experiencing an inability or unwillingness to pay suppliers, including us. The global economic environment in the past has experienced significant deterioration in a relatively short period, and there is no assurance that the global economic environment will not quickly deteriorate again due to one or more factors, including a decline in the price for oil or natural gas. A deterioration in the global economic environment could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Excess Equipment and a Highly Competitive Oil Service Industry May Adversely Affect Our Utilization and Profit Margins and the Carrying Value of our Assets.

The North American land drilling and pressure pumping businesses are highly competitive, and at times available land drilling rigs and pressure pumping equipment exceed the demand for such equipment. A low commodity price environment can result in substantially more drilling rigs and pressure pumping equipment being available than are needed to meet demand. In addition, in recent years there has been a substantial increase in the construction of new technology drilling rigs and new pressure pumping equipment and the improvement of existing drilling rigs. Low commodity prices and construction of new equipment and the improvement of existing drilling rigs can result in excess capacity and substantial competition for a declining number of drilling and pressure pumping contracts. Even in an environment of high oil and natural gas prices and increased drilling activity, reactivation and improvement of existing drilling rigs and pressure pumping equipment, construction of new technology drilling rigs and new pressure pumping equipment, and movement of drilling rigs and pressure pumping equipment from region to region in response to market conditions or otherwise can lead to an excess supply of equipment. In addition, we may be unable to replace fixed-term contracts that were terminated early, extend expiring contracts or obtain new contracts in the spot market, and the rates and other material terms under any new or extended contracts may be on substantially less favorable rates and terms. Accordingly, high competition and excess equipment can cause drilling, pressure pumping and directional drilling contractors to have difficulty maintaining utilization and profit margins and, at times, result in operating losses. We cannot predict the future level of competition or excess equipment in the oil and natural gas contract drilling, pressure pumping or directional drilling businesses or the level of demand for our contract drilling, pressure pumping or directional drilling services.

The excess supply of operable land drilling rigs, increasing rig specialization and excess pressure pumping and directional drilling equipment, which has been exacerbated by a decline in oil and natural gas prices could affect the fair market value of our drilling, pressure pumping and directional drilling equipment, which in turn could result in additional impairments of our assets. A prolonged period of lower oil and natural gas prices could result in future impairment to our long-lived assets and goodwill.

Our Operations Are Subject to a Number of Operational Risks, Including Environmental and Weather Risks, Which Could Expose Us to Significant Losses and Damage Claims. We Are Not Fully Insured Against All of These Risks and Our Contractual Indemnity Provisions May Not Fully Protect Us.

Our operations are subject to many hazards inherent in the businesses in which we operate, including inclement weather, blowouts, well fires, loss of well control, pollution, exposure and reservoir damage. These hazards could cause personal injury or death, work stoppage, and serious damage to equipment and other property, as well as significant environmental and reservoir damages. These risks could expose us to substantial liability for personal injury, wrongful death, property damage, loss of oil and natural gas production, pollution and other environmental damages.

We have indemnification agreements with many of our customers, and we also maintain liability and other forms of insurance. In general, our customer contracts typically contain provisions requiring our customers to indemnify us for, among other things, reservoir and certain pollution damage. Our right to indemnification may, however, be unenforceable or limited due to negligent or willful acts or omissions by us, our subcontractors and/or suppliers. In addition, certain states, including Louisiana, New Mexico, Texas and Wyoming, have enacted statutes generally referred to as "oilfield anti-indemnity acts" expressly prohibiting certain indemnity agreements contained in or related to oilfield services agreements. Such oilfield anti-indemnity acts may restrict or void a party's indemnification of us.

Our customers and other third parties may dispute, or be unable to meet, their indemnification obligations to us due to financial, legal or other reasons. Accordingly, we may be unable to transfer these risks to our customers and other third parties by contract or indemnification agreements. Incurring a liability for which we are not fully indemnified or insured could have a material adverse effect on our business, financial condition, cash flows and results of operations.

We maintain insurance coverage of types and amounts that we believe to be customary in the industry, but we are not fully insured against all risks, either because insurance is not available or because of the high premium costs. The insurance coverage that we maintain includes insurance for fire, windstorm and other risks of physical loss to our equipment and certain other assets, employer's liability, automobile liability, commercial general liability, workers' compensation and insurance for other specific risks. We cannot assure, however, that any insurance obtained by us will be adequate to cover any losses or liabilities, or that this insurance will continue to be available or available on terms that are acceptable to us. While we carry insurance to cover physical damage to, or loss of, a substantial portion of our equipment and certain other assets, such insurance does not cover the full replacement cost of such equipment or other assets. We have also elected in some cases to accept a greater amount of risk through increased deductibles on certain insurance policies. For example, we generally maintain a $1.5 million per occurrence deductible on our workers' compensation insurance coverage, a $1.0 million per occurrence deductible on our equipment insurance coverage, a $2.0 million per occurrence deductible on our general liability coverage, and a $2.0 million per occurrence deductible on our automobile liability insurance coverage. We also self-insure a number of other risks, including loss of earnings and business interruption and cyber risks, and we do not carry a significant amount of insurance to cover risks of underground reservoir damage.

Our insurance will not in all situations provide sufficient funds to protect us from all liabilities that could result from our operations. Our coverage includes aggregate policy limits and exclusions. As a result, we retain the risk for any loss in excess of these limits or that is otherwise excluded from our coverage. There can be no assurance that insurance will be available to cover any or all of our operational risks, or, even if available, that insurance premiums or other costs will not rise significantly in the future, so as to make the cost of such insurance prohibitive, or that our coverage will cover a specific loss. Further, we may experience difficulties in collecting from insurers or such insurers may deny all or a portion of our claims for insurance coverage. Incurring a liability for which we are not fully insured or indemnified could materially adversely affect our business, financial condition, cash flows and results of operations.

On January 22, 2018, an accident at a drilling site in Pittsburg County, Oklahoma resulted in the losses of life of five people, including three of our employees. Based on the information we have available as of the date of this Report, we believe that we have adequate insurance to cover any losses, excluding the applicable insurance deductibles and investigation-related expenses. However, if this accident is not, or another significant accident or other event occurs that is not, fully covered by insurance or an enforceable and recoverable indemnity from a third party, it could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our Current Backlog of Contract Drilling Revenue May Decline and May Not Ultimately Be Realized, as Fixed-Term Contracts May in Certain Instances Be Terminated Without an Early Termination Payment.

Fixed-term drilling contracts customarily provide for termination at the election of the customer, with an early termination payment to us if a contract is terminated prior to the expiration of the fixed term. However, in certain circumstances, for example, destruction of a drilling rig that is not replaced within a specified period of time, our bankruptcy, or a breach of our contract obligations, the customer may not be obligated to make an early termination payment to us. Additionally, during depressed market conditions or otherwise, customers may be unable to satisfy their contractual obligations or may seek to terminate or renegotiate or otherwise fail to honor their contractual obligations. In addition, we may not be able to perform under these contracts due to events beyond our control, and our customers may seek to terminate or renegotiate our contracts for various reasons, including those described above. As a result, we may be unable to realize all of our current contract drilling backlog. In addition, the termination or renegotiation of fixed-term contracts without the receipt of early termination payments could have a material adverse effect on our business, financial condition, cash flows and results of operations. As of December 31, 2017, our contract drilling backlog for future revenues under term contracts, which we define as contracts with a fixed term of six months or more, was approximately $544 million. Our contract drilling backlog may decline, as fixed-term drilling contract coverage over time may not be offset by new contracts, including as a result of the decline in the price of oil and natural gas, capital spending reductions by our customers or other factors. For these and other reasons, our contract drilling backlog may not generate sufficient liquidity for us during periods of reduced demand for our services.

New Technologies May Cause Our Operating Methods, Equipment and Services to Become Less Competitive, and Higher Levels of Capital Expenditures May Be Necessary to Remain Competitive in Our Industry.

The market for our services is characterized by continual technological and process developments that have resulted in, and will likely continue to result in, substantial improvements in the functionality and performance of drilling rigs and other equipment. Our customers are increasingly demanding the services of newer, higher specification drilling rigs and other equipment. Accordingly, a higher level of capital expenditures may be required to maintain and improve existing rigs and other equipment and purchase and construct newer, higher specification drilling rigs and other equipment to meet the increasingly sophisticated needs of our customers. In addition, technological changes, process improvements and other factors that increase operational efficiencies could continue to result in oil and natural gas wells being drilled and completed more quickly, which could reduce the number of revenue earning days. Technological and process developments in the pressure pumping and directional drilling businesses could have similar effects.

In recent years, we have added drilling rigs to our fleet through new construction, purchased new pressure pumping equipment and acquired a directional drilling services company. We have also improved existing drilling rigs and pressure pumping equipment by adding equipment designed to enhance functionality and performance. Although we take measures to ensure that we use advanced oil and natural gas drilling, pressure pumping and directional drilling technology, changes in technology, improvements in competitors’ equipment and changes relating to the wells to be drilled and completed could make our equipment less competitive.

If we are not successful keeping pace with technological advances in a timely and cost-effective manner, demand for our services may decline. If any technology that we need to successfully compete is not available to us or that we implement in the future does not work as we expect, we may be adversely affected. Additionally, new technologies, services or standards could render some of our equipment and services obsolete, which could have a material adverse impact on our business, financial condition, cash flows and results of operation.

Shortages, Delays in Delivery, and Interruptions in Supply, of Equipment and Materials Could Adversely Affect Our Operating Results.

During periods of increased demand for oilfield services, the industry has experienced shortages of equipment for upgrades, drill pipe, replacement parts and other equipment and materials, including, in the case of our pressure pumping operations, proppants, acid, gel and water. These shortages can cause the price of these items to increase significantly and require that orders for the items be placed well in advance of expected use. In addition, any interruption in supply could result in significant delays in delivery of equipment and materials or prevent operations. Interruptions may be caused by, among other reasons:

- weather issues, whether short-term such as a hurricane, or long-term such as a drought,
- transportation and other logistical challenges, and
- a shortage in the number of vendors able or willing to provide the necessary equipment and materials, including as a result of commitments of vendors to other customers or third parties or bankruptcies or consolidation.

These price increases, delays in delivery and interruptions in supply may require us to increase capital and repair expenditures and incur higher operating costs. Severe shortages, delays in delivery and interruptions in supply could limit our ability to operate, maintain, upgrade and construct our drilling rigs and pressure pumping and other equipment and could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Loss of Key Personnel and Competition for Experienced Personnel May Negatively Impact Our Financial Condition and Results of Operations.

We greatly depend on the efforts of our key employees to manage our operations. The loss of members of management could have a material adverse effect on our business. In addition, we utilize highly skilled personnel in operating and supporting our businesses. In times of increasing demand for our services, it may be difficult to attract and retain qualified personnel, particularly after a prolonged industry downturn. During periods of high demand for our services, wage rates for operations personnel are also likely to increase, resulting in higher operating costs. During periods of lower demand for our services, we may experience reductions in force and voluntary departures of key personnel, which could adversely affect our business and make it more it difficult to meet customer demands when demand for our services improves. In addition, even if it is generally a period of lower demand for our services, if there is a high demand for our services in certain areas, it may be difficult to attract and retain qualified personnel to perform services in such areas. The loss of key employees, the failure to attract and retain qualified personnel and the increase in labor costs could have a material adverse effect on our business, financial condition, cash flows and results of operations.

The Loss of Large Customers Could Have a Material Adverse Effect on Our Financial Condition and Results of Operations.

With respect to our consolidated operating revenues in 2017, we received approximately 43% from our ten largest customers, 29% from our five largest customers and 8% from our largest customer. The loss of, or reduction in business from, one or more of our larger customers could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Growth Through Acquisitions or the Building of New Rigs and Pressure Pumping Equipment Is Not Assured.

We have increased our drilling rig fleet and pressure pumping fleet and expanded our business lines in the past through mergers, acquisitions and new construction. For example, we completed the SSE merger and the MS Directional acquisition during 2017. There can be no assurance that acquisition opportunities will be available in the future or that we will be able to execute timely or efficiently any plans for building new rigs and pressure pumping equipment. We are also likely to continue to face intense competition from other companies for available acquisition opportunities. In addition, because improved technology has enhanced the ability to recover oil and natural gas, improved commodity prices may cause contract drillers to continue to build new, high technology rigs and providers of pressure pumping services to continue to build new, high horsepower equipment.

There can be no assurance that we will:

- have sufficient capital resources to complete additional acquisitions or build new rigs or pressure pumping equipment,
- successfully integrate additional drilling rigs, pressure pumping equipment or other assets or businesses, including SSE and MS Directional,
- effectively manage the growth and increased size of our organization, drilling fleet and pressure pumping equipment,
- successfully deploy idle, stacked, upgraded or additional rigs and pressure pumping equipment,
- maintain the crews necessary to operate additional drilling rigs and pressure pumping equipment, or
- successfully improve our financial condition, results of operations, business or prospects as a result of any completed acquisition or the building of new drilling rigs and pressure pumping equipment.

Our failure to achieve consolidation savings, to integrate acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our business. In addition, we may incur liabilities arising from events prior to any acquisitions or prior to our establishment of adequate compliance oversight. While we generally seek to obtain indemnities for liabilities for events occurring before such acquisitions, these are limited in amount and duration, may be held to be unenforceable or the seller may not be able to indemnify us.

We may incur substantial indebtedness to finance future acquisitions, build new drilling rigs or build new pressure pumping equipment, and we also may issue equity, convertible or debt securities in connection with any such acquisitions or building program. Debt service requirements could represent a significant burden on our results of operations and financial condition, and the issuance of additional equity or convertible securities could be dilutive to existing stockholders. Also, continued growth could strain our management, operations, employees and other resources.

Environmental and Occupational Health and Safety Laws and Regulations, Including Violations Thereof, Could Materially Adversely Affect Our Operating Results.

Our business is subject to numerous federal, state, foreign, regional and local laws, rules and regulations governing the discharge of substances into the environment, protection of the environment and worker health and safety, including, without limitation, laws concerning the containment and disposal of hazardous substances, oil field waste and other waste materials, the use of underground storage tanks, and the use of underground injection wells. The cost of compliance with these laws and regulations could be substantial. A failure to comply with these requirements could expose us to:

- substantial civil, criminal and/or administrative penalties,
- modification, denial or revocation of permits or other authorizations,
- imposition of limitations on our operations, and
- performance of site investigatory, remedial or other corrective actions.

In addition, environmental laws and regulations in the countries in which we operate impose a variety of requirements on “responsible parties” related to the prevention of spills and liability for damages from such spills. As an owner and operator of land-based drilling rigs and pressure pumping equipment, a manufacturer and servicer of oilfield service equipment and a provider of directional drilling services, we may be deemed to be a responsible party under these laws and regulations.

Changes in environmental laws and regulations occur frequently and such laws and regulations tend to become more stringent over time. Stricter laws, regulations or enforcement policies could significantly increase compliance costs for us and our customers and have a material adverse effect on our operations or financial position. For example, on August 16, 2012, the EPA issued final rules that establish new air emission control requirements for natural gas and NGL production, processing and transportation activities, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds and National Emissions Standards for Hazardous Air Pollutants (“NESHAPS”) to address hazardous air pollutants frequently associated with gas production and processing activities. In June 2016, the EPA published a final rule that updates and expands the New Source Performance Standards by setting additional emissions limits for volatile organic compounds and regulating methane emissions for new and modified sources in the oil and gas industry. In addition, the EPA has announced that it intends to impose methane emission standards for existing sources and has issued information collection requests for oil and natural gas facilities. The EPA also published a final rule in June 2016 concerning aggregation of sources that affects source determinations for air permitting in the oil and gas industry. In November 2016, the Department of the Interior issued final rules relating to the venting, flaring and leaking of natural gas by oil and natural gas producers who operate on federal and Indian lands. The rules limited routine flaring of natural gas, require the payment of royalties on avoidable gas losses and require plans or programs relating to gas capture and leak detection and repair. The EPA issued a two-year stay of these requirements in December 2017 and has indicated that the requirements could be rescinded or significantly revised in the future. These or other initiatives could increase costs to us and our customers or reduce demand for our services, which could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Potential Legislation and Regulation Covering Hydraulic Fracturing or Other Aspects of the Oil and Gas Industry Could Increase Our Costs and Limit or Delay Our Operations.

Members of the U.S. Congress and the EPA are reviewing proposals for more stringent regulation of hydraulic fracturing, a technology employed by our pressure pumping business, which involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production. For example, the EPA conducted a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. As part of this study, the EPA sent requests to a number of companies, including our company, for information on hydraulic fracturing practices. We responded to the inquiry. The EPA released its final report in December 2016. It concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. Further, we conduct drilling, pressure pumping and directional drilling activities in numerous states. Some parties believe that there is a correlation between hydraulic fracturing and other oilfield related activities and the increased occurrence of seismic activity. When caused by human activity, such seismic activity is called induced seismicity. The extent of this correlation, if any, is the subject of studies of both state and federal agencies. In addition, a number of lawsuits have been filed against other industry participants alleging damages and regulatory violations in connection with such activity. These and other ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act (“SDWA”) and other aspects of the oil and gas industry.

In addition, legislation has been proposed, but not enacted, in the U.S. Congress to amend the SDWA to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process are impairing ground water or causing other damage. These bills, if enacted, could establish an additional level of regulation at the federal or state level that could limit or delay operational activities or increase operating costs and could result in additional regulatory burdens that could make it more difficult to perform or limit hydraulic fracturing and increase our costs of compliance and doing business.

Regulatory efforts at the federal level and in many states have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. The EPA has asserted federal regulatory authority over hydraulic fracturing using fluids that contain “diesel fuel” under the SDWA Underground Injection Control Program and has released a revised guidance regarding the process for obtaining a permit for hydraulic fracturing involving diesel fuel. In May 2014, the EPA issued an Advanced Notice of Proposed Rulemaking, seeking comment on the development of regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. Further, in March 2015, the Bureau of Land Management (“BLM”) issued a final rule to regulate hydraulic fracturing on Indian land. The rule requires companies to publicly disclose chemicals used in hydraulic fracturing operations to the BLM. However, these rules were rescinded by rule in December 2017. In June 2016, the EPA published final pretreatment standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works. These regulatory initiatives could each spur further action toward federal and/or state legislation and regulation of hydraulic fracturing activities. Certain states where we operate have adopted or are considering disclosure legislation and/or regulations. For example, Colorado, Louisiana, Montana, North Dakota, Texas and Wyoming have adopted a variety of well construction, set back and disclosure regulations limiting how fracturing can be performed and requiring various degrees of chemical disclosure. Additional regulation could increase the costs of conducting our business and could materially reduce our business opportunities and revenues if our customers decrease their levels of activity in response to such regulation.

In addition, in light of concerns about induced seismicity, some state regulatory agencies have modified their regulations or issued orders to address induced seismicity. For example, the Oklahoma Corporation Commission (“OCC”) has implemented volume reduction plans, and at times required shut-ins, for oil and natural gas disposal wells injecting wastewater into the Arbuckle formation. The OCC also recently released well completion seismicity guidelines for operators in the SCOOP and STACK plays that call for hydraulic fracturing operations to be suspended following earthquakes of certain magnitudes in the vicinity.

Finally, some jurisdictions have taken steps to enact hydraulic fracturing bans or moratoria. In June 2015, New York banned high volume fracturing activities combined with horizontal drilling. Certain communities in Colorado have also enacted bans on hydraulic fracturing. Voters in the city of Denton, Texas approved a moratorium on hydraulic fracturing in November 2014, though it was later lifted in 2015. These actions have been the subject of legal challenges.

The adoption of any future federal, state, foreign, regional or local laws that impact permitting requirements for, result in reporting obligations on, or otherwise limit or ban, the hydraulic fracturing process could make it more difficult to perform hydraulic fracturing and could increase our costs of compliance and doing business and reduce demand for our services. Regulation that significantly restricts or prohibits hydraulic fracturing could have a material adverse impact on our business, financial condition, cash flows and results of operations.

The Design, Manufacture, Sale and Servicing of Products, including Rig Components, May Subject Us to Liability for Personal Injury, Property Damage and Environmental Contamination Should Such Equipment Fail to Perform to Specifications.

We provide products, including rig components such as top drives, to customers involved in oil and gas exploration, development and production. Because of applications which use our products and services, a failure of such equipment, or a failure of our customer to maintain or operate the equipment properly, could cause damage to the equipment, damage to the property of customers and others, personal injury and environmental contamination, leading to claims against us.

Legislation and Regulation of Greenhouse Gases Could Adversely Affect Our Business

We are aware of the increasing focus of local, state, regional, national and international regulatory bodies on GHG emissions and climate change issues. Legislation to regulate GHG emissions has periodically been introduced in the U.S. Congress, and there has been a wide-ranging policy debate, both in the United States and internationally, regarding the impact of these gases and possible means for their regulation. Some of the proposals would require industries to meet stringent new standards that would require substantial reductions in carbon emissions. Those reductions could be costly and difficult to implement. The EPA has adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources on an annual basis. Further, following a finding by the EPA that certain GHGs represent an endangerment to human health, the EPA finalized a rule to address permitting of GHG emissions from stationary sources under the Clean Air Act’s New Source Review Prevention of Significant Deterioration (“PSD”) and Title V programs. This final rule “tailors” the PSD and Title V programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. However, in June 2014, the U.S. Supreme Court in UARG v. EPA limited application of this rule to sources that would otherwise need permits based on emission of conventional pollutants. In April 2015, the D.C. Circuit Court of Appeals narrowed the rule in accordance with the Supreme Court's decision. In October 2015, the EPA finalized rules that added new sources to the scope of the GHG monitoring and reporting requirements. These new sources include gathering and boosting facilities as well as completions and workovers from hydraulically fractured oil wells. The revisions also include the addition of well identification reporting requirements for certain facilities. Also, in November 2016, the EPA published a final rule adding monitoring methods for detecting leaks from oil and gas equipment and emission factors for leaking equipment to be used to calculate and report GHG emissions resulting from equipment leaks. In addition, the United States was actively involved in the United Nations Conference on Climate Change in Paris, which led to the creation of the Paris Agreement. In April 2016, the United States signed the Paris Agreement, which requires countries to review and "represent a progression" in their nationally determined contributions, which set emissions reduction goals, every five years. In June 2017, President Trump announced that the United States will withdraw from the Paris Agreement unless it is renegotiated. The State Department informed the United Nations of the United States' withdrawal in August 2017. However, several states and geographic regions in the United States have adopted legislation and regulations to reduce emissions of GHGs. Additional legislation or regulation by these states and regions, the EPA, and/or any international agreements to which the United States may become a party, that control or limit GHG emissions or otherwise seek to address climate change could adversely affect our operations. The cost of complying with any new law, regulation or treaty will depend on the details of the particular program. We will continue to monitor and assess any new policies, legislation or regulations in the areas where we operate to determine the impact of GHG emissions and climate change on our operations and take appropriate actions, where necessary. Any direct and indirect costs of meeting these requirements may adversely affect our business, results of operations and financial condition. Because our business depends on the level of activity in the oil and natural gas industry, existing or future laws or regulations related to GHGs and climate change, including incentives to conserve energy or use alternative energy sources, could have a negative impact on our business if such laws or regulations reduce demand for oil and natural gas.

Legal Proceedings and Governmental Investigations Could Have a Negative Impact on Our Business, Financial Condition and Results of Operations.

The nature of our business makes us susceptible to legal proceedings and governmental investigations from time to time. For example, the January 22, 2018 accident at a drilling site in Pittsburg County, Oklahoma is currently under governmental investigation by the EPA, OSHA and the U.S. Chemical Safety and Hazard Investigation Board. In addition, during periods of depressed market conditions, we may be subject to an increased risk of our customers, vendors, current and former employees and others initiating legal proceedings against us. Lawsuits or claims against us could have a material adverse effect on our business, financial condition and results of operations. Any legal proceedings or claims, even if fully indemnified or insured, could negatively affect our reputation among our customers and the public, and make it more difficult for us to compete effectively or obtain adequate insurance in the future.

Technology Disputes Could Negatively Impact Our Operations or Increase Our Costs.

Our services and products use proprietary technology and equipment, which can involve potential infringement of a third party's rights, including patent rights. The majority of the intellectual property rights relating to our drilling rigs, pressure pumping equipment and directional drilling services are owned by us or certain of our supplying vendors. However, in the event that we or one of our supplying vendors becomes involved in a dispute over infringement rights relating to equipment owned or used by us, services performed by us or products provided by us, we may lose access to important equipment or our ability to provide services or products, or we could be required to cease use of some equipment or forced to modify our equipment, services or products. We could also be required to pay license fees or royalties for the use of equipment or provision of services or products. Technology disputes involving us or our supplying vendors could have a material adverse impact on our business, financial condition and results of operations.

Political, Economic and Social Instability Risk and Laws Associated with Conducting International Operations Could Adversely Affect Our Opportunities and Future Business.

We currently conduct operations in Canada, and we have incurred selling, general and administrative expenses related to the evaluation of and preparation for other international opportunities. Also, we sell products, including rig components, for use in numerous oil and gas producing regions outside of North America. International operations are subject to certain political, economic and other uncertainties generally not encountered in U.S. operations, including increased risks of social and political unrest, strikes, terrorism, war, kidnapping of employees, nationalization, forced negotiation or modification of contracts, difficulty resolving disputes and enforcing contractual rights, expropriation of equipment as well as expropriation of oil and gas exploration and drilling rights, changes in taxation policies, foreign exchange restrictions and restrictions on repatriation of income and capital, currency rate fluctuations, increased governmental ownership and regulation of the economy and industry in the markets in which we may operate, economic and financial instability of national oil companies, and restrictive governmental regulation, bureaucratic delays and general hazards associated with foreign sovereignty over certain areas in which operations are conducted.

There can be no assurance that there will not be changes in local laws, regulations and administrative requirements, or the interpretation thereof, which could have a material adverse effect on the cost of entry into international markets, the profitability of international operations or the ability to continue those operations in certain areas. Because of the impact of local laws, any future international operations in certain areas may be conducted through entities in which local citizens own interests and through entities (including joint ventures) in which we hold only a minority interest or pursuant to arrangements under which we conduct operations under contract to local entities. While we believe that neither operating through such entities nor pursuant to such arrangements would have a material adverse effect on our operations or revenues, there can be no assurance that we will in all cases be able to structure or restructure our operations to conform to local law (or the administration thereof) on terms we find acceptable.

There can be no assurance that we will:

- identify attractive opportunities in international markets,
- have sufficient capital resources to pursue and consummate international opportunities,
- successfully integrate international drilling rigs, pressure pumping equipment or other assets or businesses,
- effectively manage the start-up, development and growth of an international organization and assets,
- hire, attract and retain the personnel necessary to successfully conduct international operations, or
- receive awards for work and successfully improve our financial condition, results of operations, business or prospects as a result of the entry into one or more international markets.

In addition, the U.S. Foreign Corrupt Practices Act ("FCPA") and similar anti-bribery laws in other jurisdictions generally prohibit companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or retaining business. Some parts of the world where contract drilling and pressure pumping activities are conducted or where our consumers for the Warrior products are located have experienced governmental corruption to some degree and, in certain circumstances, strict compliance with anti-bribery laws may conflict with local customs and practice and could impact business. Any failure to comply with the FCPA or other anti-bribery legislation could subject to us to civil, criminal and/or administrative penalties or other sanctions, which could have a material adverse impact on our business, financial condition and results of operation. We could also face fines, sanctions and other penalties from authorities in the relevant foreign jurisdictions, including prohibition of our participating in or curtailment of business operations in those jurisdictions and the seizure of drilling rigs, pressure pumping equipment or other assets.

We may incur substantial indebtedness to finance an international transaction or operations, and we also may issue equity, convertible or debt securities in connection with any such transactions or operations. Debt service requirements could represent a significant burden on our results of operations and financial condition, and the issuance of additional equity or convertible securities could be dilutive to existing stockholders. Also, international expansion could strain our management, operations, employees and other resources.

The occurrence of one or more events arising from the types of risks described above could have a material adverse impact on our business, financial condition and results of operations.

Our Business Is Subject to Cybersecurity Risks and Threats.

Our operations are increasingly dependent on information technologies and services. Threats to information technology systems associated with cybersecurity risks and cyber incidents or attacks continue to grow, and include, among other things, storms and natural disasters, terrorist attacks, utility outages, theft, viruses, malware, design defects, human error, or complications encountered as existing systems are maintained, repaired, replaced, or upgraded. Risks associated with these threats include, among other things:

- theft or misappropriation of funds;
- loss, corruption, or misappropriation of intellectual property, or other proprietary or confidential information (including customer, supplier, or employee data);

- disruption or impairment of our and our customers' business operations and safety procedures;
- loss or damage to our worksite data delivery systems; and
- increased costs to prevent, respond to or mitigate cybersecurity events.

Although we utilize various procedures and controls to mitigate our exposure to such risk, cybersecurity attacks and other cyber events are evolving and unpredictable. Moreover, we have no control over the information technology systems of our customers, suppliers, and others with which our systems may connect and communicate. As a result, the occurrence of a cyber incident could go unnoticed for a period time. Any such incident could have a material adverse effect on our business, financial condition and results of operations.

We Are Dependent Upon Our Subsidiaries to Meet our Obligations Under Our Long-Term Debt.

We have borrowings outstanding under our senior notes and, from time to time, our revolving credit facility. These obligations are guaranteed by each of our existing U.S. subsidiaries other than immaterial subsidiaries. Our ability to meet our interest and principal payment obligations depends in large part on dividends paid to us by our subsidiaries. If our subsidiaries do not generate sufficient cash flows to pay us dividends, we may be unable to meet our interest and principal payment obligations.

Variable Rate Indebtedness Subjects Us to Interest Rate Risk, Which Could Cause Our Debt Service Obligations to Increase Significantly.

We have in place a committed senior unsecured credit facility that includes a revolving credit facility. Interest is paid on the outstanding principal amount of borrowings under the credit facility at a floating rate based on, at our election, LIBOR or a base rate. The applicable margin on LIBOR rate loans varies from 3.25% to 3.75% and the applicable margin on base rate loans varies from 2.25% to 2.75%, in each case determined based on our excess availability under the credit facility. As of December 31, 2017, the applicable margin on LIBOR rate loans was 3.50% and the applicable margin on base rate loans was 2.50%. As of December 31, 2017, we had $268 million outstanding under our revolving credit facility at a weighted average interest rate of 5.71%.

We have in place a reimbursement agreement pursuant to which we are required to reimburse the issuing bank on demand for any amounts that it has disbursed under any of our letters of credit issued thereunder. We are obligated to pay the issuing bank interest on all amounts not paid by us on the date of demand or when otherwise due at the LIBOR rate plus 2.25% per annum. As of December 31, 2017, no amounts had been disbursed under any letters of credit.

Interest rates could rise for various reasons in the future and increase our total interest expense, depending upon the amounts borrowed.

A Downgrade in Our Credit Rating Could Negatively Impact Our Cost of and Ability to Access Capital.

Our ability to access capital markets or to otherwise obtain sufficient financing is enhanced by our senior unsecured debt ratings as provided by major U.S. credit rating agencies. Factors that may impact our credit ratings include debt levels, liquidity, asset quality, cost structure, commodity pricing levels and other considerations. A ratings downgrade could adversely impact our ability in the future to access debt markets, increase the cost of future debt, and potentially require us to post letters of credit for certain obligations.

We May Not Be Able to Generate Sufficient Cash to Service All of Our Debt, Including Our Senior Notes and Debt Under Our Credit Agreement, and We May Be Forced to Take Other Actions to Satisfy Our Obligations Under Our Debt, which May Not Be Successful.

Our ability to make scheduled payments on or to refinance our debt obligations depends on our financial and operating performance, which is subject to prevailing economic and competitive conditions and to certain financial, business and other factors beyond our control. We cannot assure you that we will maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

In addition, if our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay capital expenditures, sell assets or operations, seek additional capital or restructure or refinance our debt. We cannot assure you that we would be able to take any of these actions, that these actions would be successful and would permit us to meet our scheduled debt service obligations or that these actions would be permitted under the terms of our existing or future debt agreements. In the absence of such cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. However, our Credit Agreement and senior notes contain restrictions on our ability to dispose of assets. We may not be able to consummate those dispositions, and any proceeds may not be adequate to meet any debt service obligations then due.

Anti-takeover Measures in Our Charter Documents and Under State Law Could Discourage an Acquisition and Thereby Affect the Related Purchase Price.

We are a Delaware corporation subject to the Delaware General Corporation Law, including Section 203, an anti-takeover law. Our restated certificate of incorporation authorizes our Board of Directors to issue up to one million shares of preferred stock and to determine the price, rights (including voting rights), conversion ratios, preferences and privileges of that stock without further vote or action by the holders of the common stock. It also prohibits stockholders from acting by written consent without the holding of a meeting. In addition, our bylaws impose certain advance notification requirements as to business that can be brought by a stockholder before annual stockholder meetings and as to persons nominated as directors by a stockholder. As a result of these measures and others, potential acquirers might find it more difficult or be discouraged from attempting to effect an acquisition transaction with us. This may deprive holders of our securities of certain opportunities to sell or otherwise dispose of the securities at above-market prices pursuant to any such transactions.

SSE is Subject to Continuing Contingent Tax Liabilities of Chesapeake Energy Corporation (“CHK”) Following its Spin-Off from CHK.

Under the Internal Revenue Code of 1986, as amended (the “Code”), and the related rules and regulations, each corporation that was a member of CHK’s consolidated tax reporting group during any taxable period or portion of any taxable period ending on or before June 30, 2014, the effective time of SSE’s spin-off, is jointly and severally liable for the federal income tax liability of the entire consolidated tax reporting group for that taxable period. SSE has entered into a tax sharing agreement with CHK that allocates the responsibility for prior year taxes of CHK’s consolidated tax reporting group between SSE and CHK and its subsidiaries. However, if CHK were unable to pay, SSE nevertheless could be required to pay the entire amount of such taxes.

SSE’s Tax Sharing Agreement Limits its Ability to Take Certain Actions and May Require SSE to Indemnify CHK for Significant Tax Liabilities Which Cannot be Precisely Quantified at This Time.

Under the terms of SSE’s tax sharing agreement with CHK, SSE generally is responsible for all taxes attributable to its business, whether accruing before, on or after the date of the spin-off, and CHK generally is responsible for any taxes arising from the spin-off or certain related transactions that are imposed on SSE, CHK or its other subsidiaries. Although CHK generally will be responsible for any taxes arising from the spin-off, SSE would be responsible for any such taxes to the extent such taxes result from certain actions or failures to act by SSE that occur after June 30, 2014, the effective date of the tax sharing agreement. SSE’s liabilities under the tax sharing agreement could have a material adverse effect on us. At this time, we cannot precisely quantify the amount of liabilities SSE may have under the tax sharing agreement and there can be no assurances as to their final amounts.

In addition, in the tax sharing agreement SSE covenanted not to take any action, or fail to take any action, after the effective date of the tax sharing agreement, which action or failure to act is inconsistent with the spin-off qualifying under Sections 355 and 368(a)(1)(D) of the Code. As a result, SSE might determine to continue to operate certain of its business operations for the foreseeable future even if a sale or discontinuance of such business might otherwise have been advantageous.

In Connection with SSE’s Separation from CHK, CHK Indemnified SSE for Certain Liabilities. However, There Can Be No Assurance that the Indemnities Will be Sufficient to Insure SSE Against the Full Amount of Such Liabilities, or That CHK’s Ability to Satisfy its Indemnification Obligation Will Not Be Impaired in the Future.

Pursuant to the tax sharing agreement, CHK agreed to indemnify SSE for certain liabilities. However, third parties could seek to hold SSE responsible for any of the liabilities that CHK has agreed to retain, and there can be no assurance that the indemnity from CHK will be sufficient to protect SSE against the full amount of such liabilities, or that CHK will be able to fully satisfy its indemnification obligations. Moreover, even if SSE ultimately succeeds in recovering from CHK any amounts for which SSE is held liable, SSE may be temporarily required to bear these losses. In addition, in certain circumstances, SSE will be prohibited from making an indemnity claim until it first seeks an insurance recovery. If CHK is unable to satisfy its indemnification obligations, the underlying liabilities could have a material adverse effect on our business, financial condition and results of operations.

We May Not Be Able to Utilize a Portion of SSE's or Our Net Operating Loss Carryforwards ("NOLs") to Offset Future Taxable Income for U.S. Federal Tax Purposes, Which Could Adversely Affect Our Net Income and Cash Flows.

As of December 31, 2017, SSE had federal income tax NOLs of approximately $238.0 million, which will expire between 2034 and 2037, and, as of December 31, 2017, we had federal income tax NOLs of approximately $867.1 million, which will expire between 2035 and 2037. Utilization of these NOLs depends on many factors, including our future taxable income, which cannot be predicted with any accuracy. In addition, Section 382 of the Code generally imposes an annual limitation on the amount of an NOL that may be used to offset taxable income when a corporation has undergone an "ownership change" (as determined under Section 382). Determining the limitations under Section 382 is technical and highly complex. An ownership change generally occurs if one or more shareholders (or groups of shareholders) who are each deemed to own at least 5% of the corporation's stock increase their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. In the event that an ownership change has occurred—or were to occur—with respect to a corporation following its recognition of an NOL, utilization of such NOL would be subject to an annual limitation under Section 382, generally determined by multiplying the value of the corporation's stock at the time of the ownership change by the applicable long-term tax-exempt rate as defined in Section 382. However, this annual limitation would be increased under certain circumstances by recognized built-in gains of the corporation existing at the time of the ownership change. Any unused annual limitation with respect to an NOL generally may be carried over to later years, subject to the expiration of the NOL 20 years after it arose.

SSE underwent an ownership change in 2016 as a result of its emergence from Chapter 11 bankruptcy proceedings, and experienced another ownership change in 2017 as a result of its acquisition pursuant to the SSE merger, and the corresponding annual limitation associated with either of those changes in ownership could prevent us from fully utilizing—prior to their expiration—SSE's NOLs as of the effective time of the SSE merger. While our issuance of stock pursuant to the SSE merger was, standing alone, insufficient to result in an ownership change with respect to us, we cannot assure you that we will not undergo an ownership change as a result of the merger taking into account other changes in ownership of our stock occurring within the relevant three-year period described above. If we were to undergo an ownership change, we may be prevented from fully utilizing our NOLs as of the time of the SSE merger prior to their expiration. Future changes in stock ownership or future regulatory changes could also limit our ability to utilize SSE's or our NOLs. To the extent we are not able to offset future taxable income with SSE's or our NOLs, our net income and cash flows may be adversely affected.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties

Our property consists primarily of drilling rigs, pressure pumping equipment and related equipment. We own substantially all of the equipment used in our businesses.

Our corporate headquarters is in leased office space and is located at 10713 W. Sam Houston Parkway N., Suite 800, Houston, Texas, 77064. Our telephone number at that address is (281) 765-7100. Our primary administrative office, which is located in Snyder, Texas, is owned and includes approximately 37,000 square feet of office and storage space.

Contract Drilling Operations — Our drilling services are supported by multiple offices and yard facilities located throughout our areas of operations, including Texas, Oklahoma, Colorado, North Dakota, Wyoming, Pennsylvania and western Canada.

Pressure Pumping — Our pressure pumping services are supported by multiple offices and yard facilities located throughout our areas of operations, including Texas, Oklahoma, Pennsylvania, Ohio and West Virginia.

Directional Drilling — Our directional drilling services are supported by multiple offices and yard facilities located throughout our areas of operations, including Texas, Oklahoma, Pennsylvania, Colorado and Montana.

Our Oilfield Rental operations are supported by offices and yard facilities located in Texas, Oklahoma and Ohio. Our manufacture, sale and service of pipe handling components are supported by offices and yard facilities located in western Canada and Texas. Our interests in oil and natural gas properties are primarily located in Texas and New Mexico.

We own our administrative offices in Snyder, Texas and Oklahoma City, Oklahoma, as well as several other facilities. We also lease a number of facilities, and we do not believe that any one of the leased facilities is individually material to our operations. We believe that our existing facilities are suitable and adequate to meet our needs.

We incorporate by reference in response to this item the information set forth in Item 1 of this Report and the information set forth in Note 4 of the Notes to Consolidated Financial Statements included in Item 8 of this Report.

Item 3. Legal Proceedings.

On January 22, 2018, an accident at a drilling site in Pittsburg County, Oklahoma resulted in the losses of life of five people, including three of our employees. The EPA, OSHA and the U.S. Chemical Safety and Hazard Investigation Board are currently conducting investigations related to this accident. These investigations are ongoing, and we are cooperating with the agencies regarding these investigations. The results of these investigations are not known at this time, and we are unable to determine what finding they might reach, predict what actions these agencies may require or estimate what penalties, if any, they might assess.

While we are not currently party to any claims or lawsuits relating to this accident, based on the information we have available as of the date of this Report, we believe that we have adequate insurance to cover any losses, excluding the applicable insurance deductibles and investigation-related expenses. However, if this accident is not, or another significant accident or other event occurs that is not, fully covered by insurance or an enforceable and recoverable indemnity from a third party, it could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Additionally, we are party to various legal proceedings arising in the normal course of our business. We do not believe that the outcome of these proceedings, either individually or in the aggregate, will have a material adverse effect on our financial condition, results of operations or cash flows.

Item 4. Mine Safety Disclosure.

Not applicable.

PART II

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

(a) Market Information

Our common stock, par value $0.01 per share, is publicly traded on the Nasdaq Global Select Market and is quoted under the symbol "PTEN." Our common stock is included in the S&P MidCap 400 Index and several other market indices. The following table provides high and low sales prices of our common stock for the periods indicated:

	High	Low
2017		
First quarter	$29.76	$22.83
Second quarter	25.75	19.06
Third quarter	21.74	14.83
Fourth quarter	23.26	17.24
2016		
First quarter	$18.75	$10.94
Second quarter	22.12	16.06
Third quarter	22.66	17.61
Fourth quarter	29.56	20.79

(b) Holders

As of February 16, 2018, there were approximately 1,087 holders of record of our common stock.

(c) Dividends

We paid cash dividends during the years ended December 31, 2017 and 2016 as follows:

	Per Share	Total (in thousands)
2017		
Paid on March 22, 2017	$0.02	$ 3,326
Paid on June 22, 2017	0.02	4,269
Paid on September 21, 2017	0.02	4,271
Paid on December 21, 2017	0.02	4,449
Total cash dividends	$0.08	$ 16,315
2016		

Paid on March 24, 2016	$ 0.10	$ 14,712
Paid on June 23, 2016	0.02	2,953
Paid on September 22, 2016	0.02	2,953
Paid on December 22, 2016	0.02	2,961
Total cash dividends	$ 0.16	$ 23,579

On February 7, 2018, our Board of Directors approved a cash dividend on our common stock in the amount of $0.02 per share to be paid on March 22, 2018 to holders of record as of March 8, 2018. The amount and timing of all future dividend payments, if any, are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial condition, terms of our debt agreements and other factors.

(d) Issuer Purchases of Equity Securities

The table below sets forth the information with respect to purchases of our common stock made by us during the quarter ended December 31, 2017.

Period Covered	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs (in thousands)(1)
October 2017	—	$ —	—	$ 186,544
November 2017	—	$ —	—	$ 186,544
December 2017 (2)	26,640	$ 21.98	—	$ 186,544
Total	26,640		—	$ 186,544

(1) On September 9, 2013, we announced that our Board of Directors approved a stock buyback program authorizing purchases of up to $200 million of our common stock in open market or privately negotiated transactions. All purchases executed to date have been through open market transactions. Purchases under the program are made at management's discretion, at prevailing prices, subject to market conditions and other factors. Purchases may be made at any time without prior notice. Shares of stock purchased under the plan are held as treasury shares. There is no expiration date associated with the buyback program.

(2) We withheld 26,640 shares in December 2017 with respect to exercises of stock options by directors. These shares were acquired at fair market value pursuant to the terms of the 2014 Plan and not pursuant to the stock buyback program.

(e) Performance Graph

The following graph compares the cumulative stockholder return of our common stock for the period from December 31, 2012 through December 31, 2017, with the cumulative total return of the Standard & Poors 500 Stock Index, the Standard & Poors MidCap Index, the Oilfield Service Index and a peer group determined by us. We changed our peer group in 2017 to align with the peer group used by the compensation committee of our board of directors. Our new peer group consisted of Basic Energy Services, Inc., Diamond Offshore Drilling Inc., Ensco plc., Forum Energy Technologies, Inc., Halliburton Company, Helmerich & Payne, Inc., Nabors Industries, Ltd., National Oilwell Varco, Inc., Noble Corporation plc., Oceaneering International, Oil States International Inc., Precision Drilling Corporation, Rowan Companies plc., Superior Energy Services, Inc., TechnipFMC plc, Transocean Ltd., Unit Corp. and Weatherford International plc. Our old peer group consisted of Atwood Oceanics Inc., Basic Energy Services, Inc., Diamond Offshore Drilling Inc., Ensco plc., Forum Energy Technologies, Inc., TechnipFMC plc, Helmerich & Payne, Inc., Nabors Industries, Ltd., Noble Corp., Oceaneering International, Oil States International Inc., Precision Drilling Corporation, Parker Drilling Company, Rowan Companies Inc., Superior Energy Services, Inc., Transocean Ltd., Unit Corp. and Weatherford International Ltd.

The graph assumes investment of $100 on December 31, 2012 and reinvestment of all dividends.

	Fiscal Year Ended December 31,					
	2012	2013	2014	2015	2016	2017
Company/Index	($)	($)	($)	($)	($)	($)
Patterson-UTI Energy, Inc.	100.00	137.15	91.31	85.02	153.04	131.30
S&P 500 Stock Index	100.00	132.39	150.51	152.59	170.84	208.14
S&P MidCap Index	100.00	133.50	146.54	143.35	173.08	201.20
Oilfield Service Index	100.00	129.58	99.08	75.91	90.32	74.78
New Peer Group Index	100.00	124.21	92.02	63.43	80.98	68.81
Old Peer Group Index	100.00	118.73	79.07	51.77	57.42	43.52

The foregoing graph is based on historical data and is not necessarily indicative of future performance. This graph shall not be deemed to be “soliciting material” or to be “filed” with the SEC or subject to Regulations 14A or 14C under the Exchange Act or to the liabilities of Section 18 under such Act.

Item 6. Selected Financial Data.

Our selected consolidated financial data as of December 31, 2017, 2016, 2015, 2014 and 2013, and for each of the five years in the period ended December 31, 2017, should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and related Notes thereto, included as Items 7 and 8, respectively, of this Report. The table below includes the results of operations of SSE since the merger date of April 20, 2017 and the results of operations of MS Directional since the acquisition date of October 11, 2017.

	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Operating revenues:					
Contract drilling	$1,040,033	$543,663	$1,153,892	$1,838,830	$1,679,611
Pressure pumping	1,200,311	354,070	712,454	1,293,265	979,166
Directional drilling	45,580	—	—	—	—
Other	70,760	18,133	24,931	50,196	57,257
Total	2,356,684	915,866	1,891,277	3,182,291	2,716,034
Operating costs and expenses:					
Contract drilling	667,105	305,804	608,848	1,066,659	968,754
Pressure pumping	966,835	334,588	612,021	1,036,310	744,243
Directional drilling	32,172	—	—	—	—
Other	51,428	8,384	11,500	13,102	12,909
Depreciation, depletion, amortization and impairment	783,341	668,434	864,759	718,730	597,469
Impairment of goodwill	—	—	124,561	—	—
Selling, general and administrative	105,847	69,205	74,913	80,145	73,852
Merger and integration expenses	74,451	—	—	—	—
Other operating (income) expense, net	(31,957)	(14,323)	1,647	(15,781)	(3,384)
Total	2,649,222	1,372,092	2,298,249	2,899,165	2,393,843
Operating income (loss)	(292,538)	(456,226)	(406,972)	283,126	322,191
Other expense	(35,263)	(39,970)	(35,477)	(28,843)	(25,750)
Income (loss) before income taxes	(327,801)	(496,196)	(442,449)	254,283	296,441
Income tax expense (benefit)	(333,711)	(177,562)	(147,963)	91,619	108,432
Net income (loss)	$5,910	$(318,634)	$(294,486)	$162,664	$188,009
Net income (loss) per common share:					
Basic	$0.03	$(2.18)	$(2.00)	$1.12	$1.29
Diluted	$0.03	$(2.18)	$(2.00)	$1.11	$1.28
Cash dividends per common share	$0.08	$0.16	$0.40	$0.40	$0.20
Weighted average number of common shares outstanding:					
Basic	198,447	146,178	145,416	144,066	144,356
Diluted	199,882	146,178	145,416	145,376	145,303
Balance Sheet Data:					

Total assets	$5,758,856	$3,772,291	$4,465,048	$5,353,837	$4,650,423
Borrowings under line of credit	268,000	—	—	303,000	—
Other long-term debt	598,783	598,437	787,900	667,029	678,873
Stockholders' equity	3,982,493	2,248,724	2,561,131	2,905,810	2,755,997
Working capital	200,605	(17,933)	178,887	340,816	454,498

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

Recent Developments — On January 19, 2018, we completed an offering of $525 million aggregate principal amount of our 3.95% Senior Notes due 2028 initially guaranteed on a senior unsecured basis by certain of our subsidiaries. We used $239 million of the net proceeds from the sale to repay amounts outstanding under our revolving credit facility. We intend to use the remainder of the net proceeds for general corporate purposes.

On October 11, 2017, we acquired all of the issued and outstanding limited liability company interests of MS Directional. The aggregate consideration paid by us consisted of $69.8 million in cash and approximately 8.8 million shares of our common stock. Based on the closing price of our common stock on the closing date of the transaction, the total fair value of the consideration transferred to effect the acquisition of MS Directional was approximately $257 million.

MS Directional is a leading directional drilling services company in the United States, with operations in most major producing onshore oil and gas basins. MS Directional provides a comprehensive suite of directional drilling services, including directional drilling, downhole performance motors, directional surveying, measurement while drilling, and wireline steering tools. Operational and financial data in the discussion and analysis below includes the results of operations of the MS Directional business since October 11, 2017.

On December 12, 2016, we entered into the merger agreement with SSE. On April 20, 2017, pursuant to the merger agreement, a subsidiary of ours was merged with and into SSE, with SSE continuing as the surviving entity and one of our wholly-owned subsidiaries. Pursuant to the terms of the merger agreement, we acquired all of the issued and outstanding shares of common stock of SSE, in exchange for approximately 46.3 million shares of our common stock. Concurrent with the closing of the merger, we repaid all of the outstanding debt of SSE totaling $472 million. Based on the closing price of our common stock on April 20, 2017, the total fair value of the consideration transferred to effect the acquisition of SSE was approximately $1.5 billion. On April 20, 2017, following the SSE merger, SSE was merged with and into our newly-formed subsidiary SSE LLC, with SSE LLC continuing as the surviving entity and one of our wholly-owned subsidiaries.

Through the SSE merger, we acquired a fleet of 91 drilling rigs, 36 of which we consider to be APEX® rigs. Additionally, through the SSE merger, we acquired approximately 500,000 horsepower of modern, efficient fracturing equipment located in Oklahoma and Texas. The oilfield rentals business acquired through the SSE merger has a modern, well-maintained fleet of premium oilfield rental tools, and provides specialized services for land-based oil and natural gas drilling, completion and workover activities. Operational and financial data in the discussion and analysis below includes the results of operations of the SSE businesses since April 20, 2017.

Quarterly average oil prices and our quarterly average number of rigs operating in the United States for 2015, 2016 and 2017 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2015:				
Average oil price per Bbl (1)	$48.54	$57.85	$46.42	$41.96
Average rigs operating per day - U.S. (2)	165	122	105	88
2016:				
Average oil price per Bbl (1)	$33.18	$45.41	$44.85	$49.15
Average rigs operating per day - U.S. (2)	71	55	60	66
2017:				
Average oil price per Bbl (1)	$51.77	$48.24	$48.16	$55.37
Average rigs operating per day - U.S. (2)	81	145	159	159

(1)

The average oil price represents the average monthly WTI spot price as reported by the United States Energy Information Administration.

(2) A rig is considered to be operating if it is earning revenue pursuant to a contract on a given day.

The closing price of oil was as high as $107.95 per barrel in June 2014. Prices began to fall in the third quarter of 2014 and reached a twelve-year low of $26.19 in February 2016. Oil and natural gas prices have modestly recovered from the lows experienced in the first quarter of 2016. Oil prices averaged $55.37 per barrel in the fourth quarter of 2017.

Our rig count in the United States declined significantly during the industry downturn that began in late 2014, but has improved since the second quarter of 2016. Our average rig count in the United States was 159 rigs for both the third and fourth quarter of 2017, with the third quarter of 2017 being the first quarter with a full quarter contribution from the rigs acquired in the SSE merger. Our rig count in the United States at December 31, 2017 was 163 rigs. Term contracts have supported our operating rig count during the last three years. Based on contracts currently in place, we expect an average of 96 rigs operating under term contracts during the first quarter of 2018 and an average of 67 rigs operating under term contracts throughout 2018.

Activity levels in our pressure pumping business also improved during 2017, especially in the Permian Basin. We reactivated two frac spreads during the third quarter, and one additional frac spread during the fourth quarter. With the addition of these three frac spreads, we exited 2017 with 23 active frac spreads or approximately 1.25 million active fracturing horsepower.

Management Overview — We are a Houston, Texas-based oilfield services company that primarily owns and operates in the United States one of the largest fleets of land-based drilling rigs and a large fleet of pressure pumping equipment. Our contract drilling business operates in the continental United States and western Canada, and we are pursuing contract drilling opportunities outside of North America. Our pressure pumping business operates primarily in Texas and the Mid-Continent and Appalachian regions. We also provide a comprehensive suite of directional drilling services in most major producing onshore oil and gas basins in the United States. We have other operations through which we provide oilfield rental tools in select markets in the United States, and we also manufacture and sell pipe handling components and related technology to drilling contractors in North America and other select markets. In addition, we own and invest, as a non-operating working interest owner, in oil and natural gas assets that are primarily located in Texas and New Mexico.

We have addressed our customers' needs for drilling horizontal wells in shale and other unconventional resource plays by expanding our areas of operation and improving the capabilities of our drilling fleet during the last several years. As of December 31, 2017, our rig fleet included 199 APEX® rigs.

In connection with the development of horizontal shale and other unconventional resource plays, in the last five years we have added equipment to perform service intensive fracturing jobs. As of December 31, 2017, we had approximately 1.6 million horsepower in our pressure pumping fleet. In recent years, the industry-wide addition of new pressure pumping equipment to the marketplace and lower oil and natural gas prices have led to an excess supply of pressure pumping equipment in North America.

We maintain a backlog of commitments for contract drilling revenues under term contracts, which we define as contracts with a fixed term of six months or more. Our contract drilling backlog as of December 31, 2017 and 2016 was $544 million and $417 million, respectively. Approximately 19% of the total contract drilling backlog at December 31, 2017 is reasonably expected to remain after 2018. We generally calculate our backlog by multiplying the dayrate under our term drilling contracts by the number of days remaining under the contract. The calculation does not include any revenues related to other fees such as for mobilization, demobilization and customer reimbursables, nor does it include potential reductions in rates for unscheduled standby or during periods in which the rig is moving or incurring maintenance and repair time in excess of what is permitted under the drilling contract. In addition, our term drilling contracts are generally subject to termination by the customer on short notice and provide for an early termination payment to us in the event that the contract is terminated by the customer. For contracts that we have received an early termination notice, our backlog calculation includes the early termination rate, instead of the dayrate, for the period we expect to receive the lower rate. See "Item 1A. Risk Factors – Our Current Backlog of Contract Drilling Revenue May Continue to Decline and May Not Ultimately Be Realized, as Fixed-Term Contracts May in Certain Instances Be Terminated Without an Early Termination Payment."

Our revenues, profitability and cash flows are highly dependent upon prevailing prices for oil and natural gas. During periods of improved commodity prices, the capital spending budgets of oil and natural gas operators tend to expand, which generally results in increased demand for our services. Conversely, in periods when these commodity prices deteriorate, the demand for our services generally weakens, and we experience downward pressure on pricing for our services. We are also highly impacted by operational risks, competition, the availability of excess equipment, labor issues, weather and various other factors that could materially adversely affect our business, financial condition, cash flows and results of operations. Please see "Risk Factors" in Item 1A of this Report.

For the three years ended December 31, 2017, our operating revenues consisted of the following (dollars in thousands):

	2017		2016		2015	
Contract drilling	$1,040,033	44.1 %	$543,663	59.4 %	$1,153,892	61.0 %
Pressure pumping	1,200,311	50.9 %	354,070	38.7 %	712,454	37.7 %
Directional drilling	45,580	1.9 %	—	— %	—	— %
Other	70,760	3.1 %	18,133	1.9 %	24,931	1.3 %
	$2,356,684	100.0%	$915,866	100.0%	$1,891,277	100.0%

Generally, the revenues in our contract drilling segment are most impacted by two primary factors: our average number of rigs operating and our average revenue per operating day. During 2017, our average number of rigs operating was 136 in the United States and two in Canada, compared to 63 in the United States and two in Canada in 2016, and 120 in the United States and four in Canada in 2015. Our average rig revenue per operating day was $20,620 in 2017, compared to $23,040 in 2016 and $25,560 in 2015.

Generally, the revenues in our pressure pumping segment are most impacted by our number of fracturing jobs and the size (including whether or not we provide proppant and other materials) of those jobs, which is reflected in our average revenue per fracturing job. We completed 622 fracturing jobs during 2017 compared to 352 fracturing jobs in 2016 and 610 fracturing jobs in 2015. Our average revenue per fracturing job was $1.894 million in 2017 compared to $982,560 in 2016 and $1.118 million in 2015.

For the three years ended December 31, 2017, our operating income (loss) consisted of the following (dollars in thousands):

	2017		2016		2015	
Contract drilling	$(171,897)	58.8 %	$(235,858)	51.7 %	$(78,970)	19.4 %
Pressure pumping	21,028	(7.2)%	(176,628)	38.7 %	(254,998)	62.7 %
Directional drilling	(21)	— %	—	— %	—	— %
Other	(20,813)	7.1 %	(3,391)	0.7 %	(14,269)	3.5 %
Corporate	(120,835)	41.3 %	(40,349)	8.9 %	(58,735)	14.4 %
	$(292,538)	100.0%	$(456,226)	100.0%	$(406,972)	100.0%

Discussion of our operating income (loss) follows in the "Results of Operations" section of Management's Discussion and Analysis of Financial Condition and Results of Operations.

On December 22, 2017, significant U.S. tax law changes were enacted ("tax reform"). Tax reform reduces the U.S. federal corporate tax rate from 35% to 21% beginning in 2018, requires companies to pay a one-time transition tax on foreign earnings that were previously tax deferred, creates new taxes on future foreign earnings, places a limitation on the tax deductibility of interest expense, accelerates the expensing of certain business assets, and reduces the amount of executive pay that will be tax deductible, among other changes. At December 31, 2017, we had not completed our accounting for the tax effects of the tax reform, however, in certain cases, we have made a reasonable estimate of the effects on our existing deferred tax balances and the one-time transition tax. For the items for which we were able to determine a reasonable estimate, we recognized a provisional amount in accordance with Staff Accounting Bulletin (SAB) 118 of approximately $219 million of tax benefit as a result of tax reform, which is included as a component of income tax expense from continuing operations. See Note 12 of Notes to Consolidated Financial Statements contained in this Report for additional information related to the impact of tax reform.

The improvement in demand for our services and the income tax rate change resulted in consolidated net income of $5.9 million for 2017 compared to a consolidated net loss of $319 million for 2016 and a consolidated net loss of $294 million for 2015.

Results of Operations

Comparison of the years ended December 31, 2017 and 2016

The following tables summarize results of operations by business segment for the years ended December 31, 2017 and 2016:

	Year Ended December 31,		
Contract Drilling	2017	2016	% Change
	(Dollars in thousands)		
Revenues	$1,040,033	$543,663	91.3 %
Direct operating costs	667,105	305,804	118.1 %
Margin (1)	372,928	237,859	56.8 %
Selling, general and administrative	5,934	5,743	3.3 %
Depreciation, amortization and impairment	538,891	467,974	15.2 %

Operating loss	$(171,897)	$(235,858)	(27.1)%
Operating days	50,427	23,596	113.7 %
Average revenue per operating day	$20.62	$23.04	(10.5)%
Average direct operating costs per operating day	$13.23	$12.96	2.1 %
Average margin per operating day (1)	$7.40	$10.08	(26.6)%
Average rigs operating	138.2	64.5	114.3 %
Capital expenditures	$354,425	$72,508	388.8 %

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, amortization and impairment and selling, general and administrative expenses. Average margin per operating day is defined as margin divided by operating days.

The demand for our contract drilling services is impacted by the market price of oil and natural gas. The average market price of oil and natural gas for each of the fiscal quarters and full year in 2017 and 2016 follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year
2017:					
Average oil price per Bbl (1)	$51.77	$48.24	$48.16	$55.37	$50.88
Average natural gas price per Mcf (2)	$3.01	$3.08	$2.95	$2.90	$2.99
2016:					
Average oil price per Bbl (1)	$33.18	$45.41	$44.85	$49.15	$43.15
Average natural gas price per Mcf (2)	$2.00	$2.14	$2.88	$3.04	$2.51

(1) The average oil price represents the average monthly WTI spot price as reported by the United States Energy Information Administration.
(2) The average natural gas price represents the average monthly Henry Hub Spot price as reported by the United States Energy Information Administration.

Revenues and direct operating costs increased primarily due to an increase in operating days. Operating days and average rigs operating increased due to a recovery in the oil and natural gas industry and the rigs acquired in the SSE merger. Depreciation, amortization and impairment increased due to the additional SSE assets and due to a $29.0 million impairment from the write-down of drilling equipment with no continuing utility as a result of the upgrade of certain rigs to super-spec capability. There was no similar charge in 2016. Average revenue per operating day decreased during 2017 due to a reduction in early termination revenue and the expiration of higher day rate, legacy long-term rig contracts. Early termination revenue in 2017 was $4.9 million, compared to $24.6 million in 2016. Average direct operating costs per operating day increased as a result of a reduction in the proportion of rigs on standby and an increase in rig reactivation expenses. Capital expenditures increased due to upgrading rigs to super-spec capability, building a new rig, higher maintenance capital expenditures and other general property and equipment upgrades.

Pressure Pumping	Year Ended December 31, 2017	2016	% Change
	(Dollars in thousands)		
Revenues	$1,200,311	$354,070	239.0 %
Direct operating costs	966,835	334,588	189.0 %
Margin (1)	233,476	19,482	1,098.4 %
Selling, general and administrative	14,442	11,238	28.5 %
Depreciation, amortization and impairment	198,006	184,872	7.1 %
Operating income (loss)	$21,028	$(176,628)	NA
Fracturing jobs	622	352	76.7 %
Other jobs	1,262	799	57.9 %
Total jobs	1,884	1,151	63.7 %
Average revenue per fracturing job	$1,894.40	$982.56	92.8 %
Average revenue per other job	$17.43	$10.28	69.6 %
Average revenue per total job	$637.11	$307.62	107.1 %
Average direct operating costs per total job	$513.18	$290.69	76.5 %
Average margin per total job (1)	$123.93	$16.93	632.0 %
Margin as a percentage of revenues (1)	19.5 %	5.5 %	254.5 %
Capital expenditures	$171,436	$39,584	333.1 %

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, amortization and impairment and selling, general and administrative expenses. Average margin per total job is defined as margin divided by

total jobs. Margin as a percentage of revenues is defined as margin divided by revenues.

Revenues and direct operating costs increased in 2017 primarily due to an increase in the number and size of fracturing jobs. The total number of jobs increased as a result of the SSE merger and a recovery in the oil and natural gas industry. Average revenue per job increased due to improved pricing and an increase in the size of the jobs. Average direct operating costs per total job increased primarily due to the increase in the size of the jobs. Selling, general and administrative expenses increased due to the increase in organizational size and activity as a result of the SSE merger. The increase in capital expenditures was primarily due to higher maintenance capital expenditures as a result of higher activity and investments to reactivate frac spreads.

Directional Drilling	Year Ended December 31, 2017	2016	% Change
	(Dollars in thousands)		
Revenues	$45,580	$ —	NA
Direct operating costs	32,172	—	NA
Margin (1)	13,408	—	NA
Selling, general and administrative	4,082	—	NA
Depreciation and amortization	9,347	—	NA
Operating loss	$(21)	$ —	NA
Capital expenditures	$7,795	$ —	NA

(1) Margin is defined as revenues less direct operating costs and excludes depreciation and amortization and selling, general and administrative expenses.

Our directional drilling segment originated with the October 11, 2017 acquisition of MS Directional, and consequently we have no results for the prior year in this segment.

Other Operations	Year Ended December 31, 2017	2016	% Change
	(Dollars in thousands)		
Revenues	$70,760	$18,133	290.2 %
Direct operating costs	51,428	8,384	513.4 %
Margin (1)	19,332	9,749	98.3 %
Selling, general and administrative	10,743	3,026	255.0 %
Depreciation, depletion and impairment	29,402	10,114	190.7 %
Operating loss	$(20,813)	$(3,391)	513.8 %
Capital expenditures	$31,547	$6,116	415.8 %

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, depletion and impairment and selling, general and administrative expenses.

Revenues, direct operating costs, selling, general and administrative expense and depreciation expense from other operations increased primarily as a result of the inclusion of our oilfield rental business acquired in the SSE merger on April 20, 2017 and our pipe handling components and related technology business acquired in September 2016. The increase in capital expenditures was primarily due to investments in the oilfield rental business and in oil and natural gas working interests.

Corporate	Year Ended December 31, 2017	2016	% Change
	(Dollars in thousands)		
Selling, general and administrative	$70,646	$49,198	43.6 %
Merger and integration expenses	$74,451	$—	NA
Depreciation	$7,695	$5,474	40.6 %
Other operating (income) expense, net			
Net gain on asset disposals	$(33,510)	$(14,771)	126.9 %

Other, including legal settlements, net of insurance reimbursements	1,553	448	246.7 %
Other operating income, net	$(31,957)	$(14,323)	123.1 %
Interest income	$1,866	$327	470.6 %
Interest expense	$37,472	$40,366	(7.2)%
Other income	$343	$69	397.1 %
Capital expenditures	$1,884	$1,591	18.4 %

Selling, general and administration expense increased in 2017 primarily due to the personnel added as a result of the SSE merger. The merger and integration expenses incurred in 2017 are related to the SSE merger and MS Directional acquisition. Other operating income includes net gains associated with the disposal of assets. Accordingly, the related gains or losses have been excluded from the results of specific segments. The 2017 period includes a gain of $11.2 million related to the sale of real estate and $8.4 million from the sale of certain oil and gas properties. Interest income increased due to our investment of the proceeds from our stock offering in the first quarter of 2017 prior to utilizing those proceeds to repay SSE indebtedness. Interest expense decreased primarily due to lower debt outstanding during 2017 compared to 2016.

Comparison of the years ended December 31, 2016 and 2015

The following tables summarize results of operations by business segment for the years ended December 31, 2016 and 2015:

	Year Ended December 31,		
Contract Drilling	2016	2015	% Change
	(Dollars in thousands)		
Revenues	$543,663	$1,153,892	(52.9)%
Direct operating costs	305,804	608,848	(49.8)%
Margin (1)	237,859	545,044	(56.4)%
Selling, general and administrative	5,743	5,580	2.9 %
Depreciation, amortization and impairment	467,974	618,434	(24.3)%
Operating loss	$(235,858)	$(78,970)	198.7 %
Operating days	23,596	45,142	(47.7)%
Average revenue per operating day	$23.04	$25.56	(9.9)%
Average direct operating costs per operating day	$12.96	$13.49	(3.9)%
Average margin per operating day (1)	$10.08	$12.07	(16.5)%
Average rigs operating	$64.5	$123.7	(47.9)%
Capital expenditures	$72,508	$527,054	(86.2)%

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, amortization and impairment and selling, general and administrative expenses. Average margin per operating day is defined as margin divided by operating days.

The demand for our contract drilling services is impacted by the market price of oil and natural gas. The reactivation and construction of new land drilling rigs in the United States in recent years contributed to an excess capacity of land drilling rigs compared to demand. Customer demand shifted away from mechanically powered drilling rigs to electric powered drilling rigs, reducing the utilization rates of our mechanically powered drilling rigs. The average market price of oil and natural gas for each of the fiscal quarters and full year in 2016 and 2015 follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year
2016:					
Average oil price per Bbl (1)	$33.18	$45.41	$44.85	$49.15	$43.15
Average natural gas price per Mcf (2)	$2.00	$2.14	$2.88	$3.04	$2.51
2015					
Average oil price per Bbl (1)	$48.54	$57.85	$46.42	$41.96	$48.69
Average natural gas price per Mcf (2)	$2.90	$2.75	$2.76	$2.12	$2.63

(1) The average oil price represents the average monthly WTI spot price as reported by the United States Energy Information Administration.

(2) The average natural gas price represents the average monthly Henry Hub Spot price as reported by the United States Energy Information Administration.

The decreases in revenues and direct operating costs primarily result from the decrease in the number of rigs operating. Average revenue per operating day and average margin per operating day were higher in 2015 primarily due to higher average dayrates and early termination revenues of approximately $69.4 million. Early termination revenues were approximately $24.6 million in 2016. Depreciation, amortization and impairment expense for 2015 included a charge of $131 million related to the write-down of drilling equipment primarily related to mechanical rigs and spare mechanical rig components. There were no similar charges in 2016. Capital expenditures were significantly lower as no new rigs were added to the fleet in 2016 and drilling activity was lower, which required less maintenance capital.

Pressure Pumping	Year Ended December 31, 2016	2015	% Change
	(Dollars in thousands)		
Revenues	$354,070	$712,454	(50.3)%
Direct operating costs	334,588	612,021	(45.3)%
Margin (1)	19,482	100,433	(80.6)%
Selling, general and administrative	11,238	16,318	(31.1)%
Depreciation, amortization and impairment	184,872	214,552	(13.8)%
Impairment of goodwill	-	124,561	NA
Operating loss	$(176,628)	$(254,998)	(30.7)%
Fracturing jobs	352	610	(42.3)%
Other jobs	799	2,080	(61.6)%
Total jobs	1,151	2,690	(57.2)%
Average revenue per fracturing job	$982.56	$1,117.95	(12.1)%
Average revenue per other job	$10.28	$14.66	(29.9)%
Average revenue per total job	$307.62	$264.85	16.1 %
Average direct operating costs per total job	$290.69	$227.52	27.8 %
Average margin per total job (1)	$16.93	$37.34	(54.7)%
Margin as a percentage of revenues (1)	5.5 %	14.1 %	(61.0)%
Capital expenditures and acquisitions	$39,584	$197,577	(80.0)%

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, amortization and impairment and selling, general and administrative expenses. Average margin per total job is defined as margin divided by total jobs. Margin as a percentage of revenues is defined as margin divided by revenues.

Revenues and direct operating costs decreased in 2016 as a result of declines in both activity and pricing. Average revenue per fracturing job and average revenue per other job decreased due to market-related pricing constraints. Average revenue per total job and average direct operating costs per total job increased as a result of a shift in the job mix toward fracturing jobs. The total number of jobs decreased as a result of the downturn in the oil and natural gas industry. Lower selling, general and administrative expense in 2016 reflects lower personnel costs due to headcount reductions. Depreciation, amortization and impairment expense for 2015 includes a charge of $22.0 million related to the write-down of pressure pumping equipment and closed facilities. There were no similar charges in 2016. In addition, all of the goodwill associated with our pressure pumping business was impaired during 2015.

Other Operations	Year Ended December 31, 2016	2015	% Change
	(Dollars in thousands)		
Revenues	$18,133	$24,931	(27.3)%
Direct operating costs	8,384	11,500	(27.1)%
Margin (1)	9,749	13,431	(27.4)%
Selling, general and administrative	3,026	1,399	116.3 %
Depreciation, depletion and impairment	10,114	26,301	(61.5)%
Operating loss	$(3,391)	$(14,269)	(76.2)%
Capital expenditures	$6,116	$16,625	(63.2)%

(1) Margin is defined as revenues less direct operating costs and excludes depreciation, depletion and impairment and selling, general and administrative expenses.

Revenues from other operations decreased as a result of lower production and lower oil prices which resulted in lower revenues from our oil and natural gas working interests. Direct operating costs include a reduction in production taxes due to lower revenues. Selling, general and administrative expense increased from 2015 as the 2016 results include costs related to our drilling technology service business which was acquired in September 2016. Depreciation, depletion and impairment expense in 2016 includes approximately $2.8 million of oil and natural gas property impairments as compared to approximately $10.7 million of oil and natural gas property impairments in 2015.

Corporate	Year Ended December 31, 2016	2015	% Change
	(Dollars in thousands)		
Selling, general and administrative	$49,198	$51,616	(4.7)%
Depreciation	$5,474	$5,472	0.0 %
Other operating (income) expense, net			
Net gain on asset disposals	$(14,771)	$(10,613)	39.2 %
Legal settlements, net of insurance reimbursements	448	12,260	(96.3)%
Other operating (income) expense, net	$(14,323)	$1,647	NA
Interest income	$327	$964	(66.1)%
Interest expense	$40,366	$36,475	10.7 %
Other income	$69	$34	102.9 %
Capital expenditures	$1,591	$2,520	(36.9)%

Lower selling, general and administrative expense reflects lower personnel costs due to headcount reductions. Other operating (income) expense, net includes net gains associated with the disposal of assets related to corporate strategy decisions of the executive management group. Accordingly, the related gains or losses have been excluded from the results of specific segments. Interest expense increased primarily due to lower capitalized interest, as we reduced our level of capital expenditures in 2016. In addition, we repaid the entire outstanding principal amount of our bank term loans. As a result, we expensed $1.4 million of previously unamortized debt issuance costs in 2016 related to these bank term loans.

Income Taxes

	Year Ended December 31, 2017	2016	2015
	(Dollars in thousands)		
Loss before income taxes	$(327,801)	$(496,196)	$(442,449)
Income tax benefit	$(333,711)	$(177,562)	$(147,963)
Effective tax rate	101.8 %	35.8 %	33.4 %

The effective tax rate is a result of a federal rate of 35.0% adjusted as follows:

	2017	2016	2015
Statutory tax rate	35.0 %	35.0%	35.0%
State income taxes - net of the federal income tax benefit	1.9	2.0	2.1
Permanent differences	(1.3)	(0.1)	(1.3)
One-time tax effects of tax reform	66.7	—	—
Share-based payments	3.6	—	—
Acquisition related differences	(3.3)	—	—
Other differences, net	(0.8)	(1.1)	(2.4)
Effective tax rate	101.8%	35.8%	33.4%

The effective tax rate increased by approximately 66.0% to 101.8% for 2017 compared to 2016, primarily due to a 66.7% increase related to the tax reform enacted on December 22, 2017 and a 3.6% increase for excess tax benefits from employee stock compensation deductions. These increases were partially offset by a 3.3% decrease in the effective tax rate for acquisitions that resulted in the revaluation of deferred tax assets and liabilities at the new state tax rates at which they are expected to reverse. The lower 2015 effective rate is primarily related to the impact of goodwill impairment charges in 2015 along with an adjustment to our deferred tax liability associated with the 2010 conversion of our Canadian operations to a controlled foreign corporation.

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Tax reform reduces the U.S. federal corporate tax rate from 35% to 21% beginning in 2018, requires companies to pay a one-time transition tax on foreign earnings that were previously tax deferred, creates new taxes on future foreign earnings, places a new limitation on the tax deductibility of interest expense, accelerates the expensing of certain business assets, and reduces the amount of executive pay that will be tax deductible, among other changes. Based on a reduced US federal corporate tax rate of 21% from tax reform, we remeasured certain deferred tax assets and liabilities at the tax rates at which they are expected to reverse in the future. Due to the limited time to consider tax reform and its various interpretations, we are still analyzing and refining our calculations, which could potentially affect the measurement of these balances or give rise to new deferred tax amounts, however, in certain cases, we have made a reasonable estimate of the effects on our existing deferred tax balances and the one-time transition tax. For the items for which we were able to determine a reasonable estimate, we recognized a provisional amount, in accordance with Staff Accounting Bulletin (SAB) 118, of approximately $219 million of tax benefit, which is included as a component of income tax expense from continuing operations resulting in the above impact to our 2017 effective tax rate. See Note 12 of Notes to Consolidated Financial Statements contained in this Report for additional information related to the impact of tax reform.

Prior to tax reform, we had elected to permanently reinvest unremitted earnings in Canada effective January 1, 2010, and we intended to do so for the foreseeable future. As a result, no deferred U.S. federal or state income taxes had been provided on such unremitted foreign earnings. With the enactment of tax reform, there is a new territorial tax system that provides for a 100% dividends received deduction on future earnings, if remitted. However, we will need to continue to evaluate our reinvestment intentions on future earnings and any other residual basis differences in order to determine whether we can continue to assert indefinite reinvestment or whether we will be required to provide for additional taxes that would be due on future earnings if remitted, such as foreign withholding taxes or state and local taxes. We will also need to determine whether we will be required to provide for additional taxes on any other outside basis differences in our foreign operations. Due to the limited time to consider these provisions, we are still evaluating how tax reform will affect our existing accounting position to indefinitely reinvest unremitted foreign earnings. We will continue to assert permanent reinvestment with respect to future unremitted earnings and have not recorded any deferred federal or state income taxes that would be provided on future unremitted earnings. We will finalize our intentions on whether we will permanently reinvest our foreign unremitted earnings within the measurement period provided under SAB 118.

We record deferred federal income taxes based primarily on the temporary differences between the book and tax bases of our assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the year in which those temporary differences are expected to be settled. As a result of fully recognizing the benefit of our deferred income taxes, we incur deferred income tax expense as these benefits are utilized. We recognized a deferred tax benefit of approximately $330 million in 2017, $152 million in 2016 and $100 million in 2015.

In March 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2016-09, “Compensation-Stock Compensation” (ASU 2016-09). The new standard was effective for us on January 1, 2017. Among other provisions, the new standard requires that excess tax benefits and tax deficiencies that arise upon vesting or exercise of share-based payments be recognized as income tax benefits and expenses in the income statement. Previously, such amounts were recorded to additional paid-in-capital. This aspect of the new guidance was required to be adopted prospectively. Our effective income tax rate for the year ended December 31, 2017 includes approximately $12 million of excess tax benefits from share-based compensation awards that vested or were exercised during the period.

During 2017, we had significant merger and acquisition activity. Based on this activity, we evaluated our overall state deferred tax rate, resulting in a slightly increased rate. We remeasured certain deferred tax assets and liabilities at the tax rates at which they are expected to reverse in the future and recorded additional taxes of approximately $11 million, resulting in the above impact to the 2017 effective tax rate.

Liquidity and Capital Resources

Our liquidity as of December 31, 2017 included approximately $201 million in working capital, including $42.8 million of cash and cash equivalents, and $227 million available under our revolving credit facility.

We believe our current liquidity, together with cash expected to be generated from operations in 2018, should provide us with sufficient ability to fund our current plans to maintain and make improvements to our existing equipment, service our debt and pay cash dividends for at least the next 12 months. If we pursue opportunities for growth that require capital, we believe we would be able to satisfy these needs through a combination of working capital, cash flows from operating activities, borrowing capacity under our revolving credit facility or additional debt or equity financing. However, there can be no assurance that such capital will be available on reasonable terms, if at all.

As of December 31, 2017, we had working capital of $201 million, including cash and cash equivalents of $42.8 million, compared to negative working capital of $17.9 million, including cash and cash equivalents of $35.2 million, at December 31, 2016.

During 2017, our sources of cash flow included:

- $301 million from operating activities,
- $60.9 million in proceeds from the disposal of property and equipment,
- $268 million in net borrowings under our revolving credit facility, and
- $472 million from net proceeds from common stock issuance.

During 2017, we used $502 million, net of cash acquired, for the acquisitions of SSE and MS Directional, $16.3 million to pay dividends on our common stock, $6.8 million to acquire shares of our common stock and $567 million:

- to make capital expenditures for the acquisition, betterment and refurbishment of drilling rigs and pressure pumping equipment,
- to acquire and procure equipment and facilities to support our drilling, pressure pumping, directional drilling, oilfield rental and manufacturing operations, and
- to fund investments in oil and natural gas properties on a non-operating working interest basis.

We paid cash dividends during the year ended December 31, 2017 as follows:

	Per Share	Total (in thousands)
Paid on March 22, 2017	$ 0.02	$ 3,326
Paid on June 22, 2017	0.02	4,269
Paid on September 21, 2017	0.02	4,271
Paid on December 21, 2017	0.02	4,449
Total cash dividends	$ 0.08	$ 16,315

On February 7, 2018, our Board of Directors approved a cash dividend on our common stock in the amount of $0.02 per share to be paid on March 22, 2018 to holders of record as of March 8, 2018. The amount and timing of all future dividend payments, if any, are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial condition, terms of our debt agreements and other factors.

On September 6, 2013, our Board of Directors approved a stock buyback program that authorizes purchase of up to $200 million of our common stock in open market or privately negotiated transactions. All purchases executed to date have been through open market transactions. Purchases under the program are made at management’s discretion, at prevailing prices, subject to market conditions and other factors. Purchases may be made at any time without prior notice. Shares of stock purchased under the plan are held as treasury shares. There is no expiration date associated with the buyback program. As of December 31, 2017, we had remaining authorization to purchase approximately $187 million of our outstanding common stock under the 2013 stock buyback program.

We acquired shares of stock from directors in 2017 and 2016 and from employees during 2017, 2016 and 2015 that are accounted for as treasury stock. Certain of these shares were acquired to satisfy the exercise price in connection with the exercise of stock options. The remainder of these shares was acquired to satisfy payroll withholding obligations upon the settlement of performance unit awards and the vesting of restricted stock. These shares were acquired at fair market value. These acquisitions were made pursuant to the terms of the Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan and not pursuant to the stock buyback program.

Treasury stock acquisitions during the years ended December 31, 2017, 2016 and 2015 were as follows (dollars in thousands):

	2017		2016		2015	
	Shares	Cost	Shares	Cost	Shares	Cost
Treasury shares at beginning of period	43,392,617	$911,094	43,207,240	$907,045	42,818,585	$899,035

Purchases pursuant to 2013 stock buyback program	5,503	109	8,488	183	8,618	180
Acquisitions pursuant to long-term incentive plan	404,491	7,508	176,889	3,866	380,037	7,830
Treasury shares at end of period	43,802,611	$918,711	43,392,617	$911,094	43,207,240	$907,045

2012 Credit Agreement — On September 27, 2012, we entered into a Credit Agreement ("Base Credit Agreement"). The Base Credit Agreement (as amended, the "Credit Agreement") is a committed senior unsecured credit facility that includes a revolving credit facility.

On July 8, 2016, we entered into Amendment No. 2 to Credit Agreement (“Amendment No. 2”), which amended the Base Credit Agreement to, among other things, make borrowings under the revolving credit facility subject to a borrowing base calculated by reference to our and certain of our subsidiaries’ eligible equipment, inventory, accounts receivable and unencumbered cash as described in Amendment No. 2. The revolving credit facility contains a letter of credit facility that is limited to $50 million and a swing line facility that is limited to $20 million, in each case outstanding at any time. The maturity date under the Base Credit Agreement was September 27, 2017 for the revolving credit facility; however, Amendment No. 2 extended the maturity date of $357.9 million in revolving credit commitments of certain lenders to March 27, 2019. On January 17, 2017, we entered into Amendment No. 3 to Credit Agreement, which amended the Credit Agreement by restating the definition of Consolidated EBITDA to provide for the add-back of transaction expenses related to the SSE merger. On January 24, 2017, we entered into an agreement with certain lenders under our revolving credit facility to increase the aggregate commitments under our revolving credit facility to approximately $595.8 million, subject to the satisfaction of certain conditions. The aggregate commitment increase became effective on April 20, 2017 upon the consummation of the SSE merger and the repayment and termination of the SSE credit facility. On April 20, 2017, we entered into Amendment No. 4 to Credit Agreement which permitted outstanding letters of credit under the SSE credit facility to be deemed to be incurred under our credit facility and increased the amount of the accordion feature of our revolving credit facility to permit aggregate commitments to be increased to an amount not to exceed $700 million (subject to satisfaction of certain conditions and the procurement of additional commitments from new or existing lenders). On April 20, 2017, we also entered into an additional commitment increase agreement with certain of our lenders pursuant to which total commitments available under our revolving credit facility (after giving effect to both commitment increases) increased to $632 million through September 2017 and to $490 million through March 2019. On October 27, 2017, we entered into an additional commitment increase agreement with certain of our lenders pursuant to which total commitments available under our revolving credit facility increased to $500 million through March 27, 2019.

Loans under the Credit Agreement bear interest by reference, at our election, to the LIBOR rate or base rate, provided, that swing line loans bear interest by reference only to the base rate. Until September 27, 2017, the applicable margin on LIBOR rate loans varied from 2.75% to 3.25% and the applicable margin on base rate loans varied from 1.75% to 2.25%, in each case determined based upon our debt to capitalization ratio. Beginning September 27, 2017, the applicable margin on LIBOR rate loans varies from 3.25% to 3.75% and the applicable margin on base rate loans varies from 2.25% to 2.75%, in each case determined based on our excess availability under the revolving credit facility. As of December 31, 2017, the applicable margin on LIBOR rate loans was 3.50% and the applicable margin on base rate loans was 2.50%. A letter of credit fee is payable by us equal to the applicable margin for LIBOR rate loans times the daily amount available to be drawn under outstanding letters of credit. The commitment fee rate payable to the lenders for the unused portion of the revolving credit facility is 0.50%.

Each of our domestic subsidiaries unconditionally guarantees all existing and future indebtedness and liabilities of the other guarantors and ours arising under the Credit Agreement, other than (a) Ambar Lone Star Fluid Services LLC, (b) domestic subsidiaries that directly or indirectly have no material assets other than equity interests in, or capitalization indebtedness owed by, foreign subsidiaries, and (c) any subsidiary having total assets of less than $1 million. Such guarantees also cover our or any of our subsidiaries arising under any interest rate swap contract with any person while such person is a lender or an affiliate of a lender under the Credit Agreement.

The Credit Agreement requires compliance with two financial covenants. We must not permit our debt to capitalization ratio to exceed 40%. The Credit Agreement generally defines the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. We also must not permit our interest coverage ratio as of the last day of a fiscal quarter to be less than 3.00 to 1.00. The Credit Agreement generally defines the interest coverage ratio as the ratio of earnings before interest, taxes, depreciation and amortization (“EBITDA”) of the four prior fiscal quarters to interest charges for the same period. We were in compliance with these covenants at December 31, 2017.

The Credit Agreement limits our ability to make investments in foreign subsidiaries or joint ventures such that, if the book value of all such investments since September 27, 2012 is above 20% of our total consolidated book value of the assets on a pro forma basis, we will not be able to make such investment. The Credit Agreement also restricts our ability to pay dividends and make equity repurchases, subject to certain exceptions, including an exception allowing such restricted payments if before and immediately after giving effect to such restricted payment, the Pro Forma Debt Service Coverage Ratio (as defined in the Credit Agreement) is at least 1.50 to 1.00. In addition, the Credit Agreement requires that, if our consolidated cash balance, subject to certain exclusions, is more than $100 million at the end of the day on which a borrowing is made, we can only use the proceeds from such borrowing to fund acquisitions, capital expenditures and the repurchase of indebtedness, and if such proceeds are not used in such manner within three business days, we must repay such unused proceeds on the fourth business day following such borrowings.

The Credit Agreement also contains customary representations, warranties and affirmative and negative covenants. We do not expect that the restrictions and covenants will impair, in any material respect, our ability to operate or react to opportunities that might arise.

Events of default under the Credit Agreement include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, as well as a cross default event, loan document enforceability event, change of control event and bankruptcy and other insolvency events. If an event of default occurs and is continuing, then a majority of the lenders have the right, among others, to (i) terminate the commitments under the Credit Agreement, (ii) accelerate and require us to repay all the outstanding amounts owed under any loan document (provided that in limited circumstances with respect to our insolvency and bankruptcy, such acceleration is automatic), and (iii) require us to cash collateralize any outstanding letters of credit.

As of December 31, 2017, we had $268 million outstanding under our revolving credit facility at a weighted average interest rate of 5.71%. We had $4.6 million in letters of credit outstanding under our revolving credit facility at December 31, 2017 and, as a result, had available borrowing capacity of $227 million at that date. As of February 16, 2018, we had repaid all amounts outstanding under our revolving credit facility, had approximately $118,000 of letters of credit outstanding under our revolving credit facility, and had borrowing capacity of $499.9 million.

2015 Reimbursement Agreement — On March 16, 2015, we entered into a Reimbursement Agreement (the “Reimbursement Agreement”) with The Bank of Nova Scotia (“Scotiabank”), pursuant to which we may from time to time request that Scotiabank issue an unspecified amount of letters of credit. As of December 31, 2017, we had $54.9 million in letters of credit outstanding under the Reimbursement Agreement.

Under the terms of the Reimbursement Agreement, we will reimburse Scotiabank on demand for any amounts that Scotiabank has disbursed under any letters of credit. Fees, charges and other reasonable expenses for the issuance of letters of credit are payable by us at the time of issuance at such rates and amounts as are in accordance with Scotiabank’s prevailing practice. We are obligated to pay to Scotiabank interest on all amounts not paid on the date of demand or when otherwise due at the LIBOR rate plus 2.25% per annum, calculated daily and payable monthly, in arrears, on the basis of a calendar year for the actual number of days elapsed, with interest on overdue interest at the same rate as on the reimbursement amounts.

We have also agreed that if obligations under the Credit Agreement are secured by liens on any of our subsidiaries’ property, then our reimbursement obligations and (to the extent similar obligations would be secured under the Credit Agreement) other obligations under the Reimbursement Agreement and any letters of credit will be equally and ratably secured by all property subject to such liens securing the Credit Agreement.

Pursuant to a Continuing Guaranty dated as of March 16, 2015 (the “Continuing Guaranty”), our payment obligations under the Reimbursement Agreement are jointly and severally guaranteed as to payment and not as to collection by our subsidiaries that from time to time guarantee payment under the Credit Agreement.

Series A & B Senior Notes — On October 5, 2010, we completed the issuance and sale of $300 million in aggregate principal amount of our 4.97% Series A Senior Notes due October 5, 2020 (the “Series A Notes”) in a private placement. The Series A Notes bear interest at a rate of 4.97% per annum. We pay interest on the Series A Notes on April 5 and October 5 of each year. The Series A Notes will mature on October 5, 2020.

On June 14, 2012, we completed the issuance and sale of $300 million in aggregate principal amounts of our 4.27% Series B Senior Notes due June 14, 2022 (the “Series B Notes”) in a private placement. The Series B Notes bear interest at a rate of 4.27% per annum. We pay interest on the Series B Notes on April 5 and October 5 of each year. The Series B Notes will mature on June 14, 2022.

The Series A Notes and Series B Notes are senior unsecured obligations, which rank equally in right of payment with all of our other unsubordinated indebtedness. The Series A Notes and Series B Notes are guaranteed on a senior unsecured basis by each of our domestic subsidiaries other than subsidiaries that are not required to be guarantors under the Credit Agreement.

The Series A Notes and Series B Notes are prepayable at our option, in whole or in part, provided that in the case of a partial prepayment, prepayment must be in an amount not less than 5% of the aggregate principal amount of the notes then outstanding, at any time and from time to time at 100% of the principal amount prepaid, plus accrued and unpaid interest to the prepayment date, plus a "make-whole" premium as specified in the note purchase agreements. We must offer to prepay the notes upon the occurrence of any change of control. In addition, we must offer to prepay the notes upon the occurrence of certain asset dispositions if the proceeds therefrom are not timely reinvested in productive assets. If any offer to prepay is accepted, the purchase price of each prepaid note is 100% of the principal amount thereof, plus accrued and unpaid interest thereon to the prepayment date.

The respective note purchase agreements require compliance with two financial covenants. We must not permit our debt to capitalization ratio to exceed 50% at any time. The note purchase agreements generally define the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. We also must not permit our interest coverage ratio as of the last day of a fiscal quarter to be less than 2.50 to 1.00. The note purchase agreements generally define the interest coverage ratio as the ratio of EBITDA for the four prior fiscal quarters to interest charges for the same period. We were in compliance with these covenants at December 31, 2017. We do not expect that the restrictions and covenants will impair, in any material respect, our ability to operate or react to opportunities that might arise.

Events of default under the note purchase agreements include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, a cross default event, a judgment in excess of a threshold event, the guaranty agreement ceasing to be enforceable, the occurrence of certain ERISA events, a change of control event and bankruptcy and other insolvency events. If an event of default under the note purchase agreements occurs and is continuing, then holders of a majority in principal amount of the respective notes have the right to declare all the notes then-outstanding to be immediately due and payable. In addition, if we default in payments on any note, then until such defaults are cured, the holder thereof may declare all the notes held by it pursuant to the note purchase agreement to be immediately due and payable.

2028 Senior Notes — On January 19, 2018, we completed an offering of $525 million aggregate principal amount of our 2028 Notes initially guaranteed on a senior unsecured basis by certain of our subsidiaries. The net proceeds before offering expenses were approximately $521 million of which we used $239 million to repay amounts outstanding under our revolving credit facility. We intend to use the remainder of the net proceeds for general corporate purposes.

We pay interest on the 2028 Notes on February 1 and August 1 of each year. The 2028 Notes will mature on February 1, 2028. The 2028 Notes bear interest at a rate of 3.95% per annum.

The 2028 Notes are our senior unsecured obligations, which rank equally with all of our other existing and future senior unsecured debt and will rank senior in right of payment to all of our other future subordinated debt. The 2028 Notes will be effectively subordinated to any of our future secured debt to the extent of the value of the assets securing such debt. In addition, the 2028 Notes will be structurally subordinated to the liabilities (including trade payables) of our subsidiaries that do not guarantee the 2028 Notes. The guarantors' guarantees of the 2028 Notes (the "Guarantees") will rank equally in right of payment with all of the guarantors' future unsecured senior debt and senior in right of payment to all of the guarantors' future subordinated debt. The Guarantees will be effectively subordinated to any of the guarantors' future secured debt to the extent of the value of the assets securing such debt. In the future, the Guarantees may be released and terminated under certain circumstances.

We, at our option, may redeem the Notes in whole or part, at any time or from time to time at a redemption price equal to 100% of the principal amount of such 2028 Notes to be redeemed, plus accrued and unpaid interest, if any, on those 2028 Notes to the redemption date, plus a make-whole premium. Additionally, commencing on November 1, 2027, we, at our option, may redeem the 2028 Notes in whole or part, at a redemption price equal to 100% of the principal amount of the 2028 Notes to be redeemed, plus accrued and unpaid interest, if any, on those 2028 Notes to the redemption date.

The indenture pursuant to which the 2028 Notes were issued includes covenants that, among other things, limit our and our subsidiaries' ability to incur certain liens, engage in sale and lease-back transactions or consolidate, merge, or transfer all or substantially all of their assets. These covenants are subject to important qualifications and limitations set forth in the indenture.

Upon the occurrence of a change of control, as defined in the indenture, each holder of the 2028 Notes may require us to purchase all or a portion of such holder's 2028 Notes at a price equal to 101% of their principal amount, plus accrued and unpaid interest, if any, to, but excluding, the repurchase date.

The indenture also provides for events of default which, if any of them occurs, would permit or require the principal of, premium, if any, and accrued interest, if any, on the 2028 Notes to become or to be declared due and payable.

Common Stock Offering — On January 27, 2017, we completed an offering of 18.2 million shares of our common stock and raised net proceeds of $472 million. We used the net proceeds of the offering to repay of SSE’s outstanding indebtedness of approximately $472 million.

Commitments and Contingencies — As of December 31, 2017, we maintained letters of credit in the aggregate amount of $59.5 million for the benefit of various insurance companies as collateral for retrospective premiums and retained losses which could become payable under the terms of the underlying insurance contracts. These letters of credit expire annually at various times during the year and are typically renewed. As of December 31, 2017, no amounts had been drawn under the letters of credit.

As of December 31, 2017, we had commitments to purchase approximately $172 million of major equipment for our drilling and pressure pumping businesses.

Our pressure pumping business has entered into agreements to purchase minimum quantities of proppants and chemicals from certain vendors. As of December 31, 2017, the remaining obligation under these agreements was approximately $140 million, of which materials with a total purchase price of approximately $35.9 million were required to be purchased during 2018. In the event that the required minimum quantities are not purchased during any contract year, we could be required to make a liquidated damages payment to the respective vendor for any shortfall.

Trading and Investing — We have not engaged in trading activities that include high-risk securities, such as derivatives and non-exchange traded contracts. We invest cash primarily in highly liquid, short-term investments such as overnight deposits and money market accounts.

Contractual Obligations

The following table presents information with respect to our contractual obligations as of December 31, 2017 (in thousands):

	Payments due by period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Revolving credit facility (1)	$268,000	$—	$268,000	$—	$—
Series A Notes (2)	300,000	—	300,000	—	—
Interest on Series A Notes (3)	44,730	14,910	29,820	—	—
Series B Notes (4)	300,000	—	—	300,000	—
Interest on Series B Notes (5)	60,102	12,810	25,620	21,672	—
Leases (6)	48,022	13,616	16,480	9,009	8,917
Equipment purchases (7)	172,123	172,123	—	—	—
Inventory purchases (8)	140,004	35,933	24,418	6,626	73,027
Total (9)	$1,332,981	$249,392	$664,338	$337,307	$81,944

(1) Revolving credit facility matures on March 27, 2019.
(2) Principal repayment of the Series A Notes is required at maturity on October 5, 2020.
(3) Interest to be paid on the Series A Notes using 4.97% coupon rate.
(4) Principal repayment of the Series B Notes is required at maturity on June 14, 2022.
(5) Interest to be paid on the Series B Notes using 4.27% coupon rate.
(6) See Note 11 of Notes to Consolidated Financial Statements.
(7) Represents commitments to purchase major equipment to be delivered in 2018 based on expected delivery dates.
(8) Represents commitments to purchase proppants and chemicals for our pressure pumping business.
(9) Excludes $525 million principal repayment of, and interest to be paid on, the 2028 Notes.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements at December 31, 2017.

Adjusted EBITDA

Adjusted earnings before interest, taxes, depreciation and amortization ("Adjusted EBITDA") is not defined by accounting principles generally accepted in the United States of America ("U.S. GAAP"). We define Adjusted EBITDA as net income (loss) plus net interest expense, income tax expense (benefit) and depreciation, depletion, amortization and impairment expense (including impairment of goodwill). We present Adjusted EBITDA because we believe it provides to both management and investors additional information with respect to the performance of our fundamental business activities and a comparison of the results of our operations from period to period and against our peers without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA should not be construed as an alternative to the U.S. GAAP measure of net income (loss). Our computations of Adjusted EBITDA may not be the same as other similarly titled measures of other companies. Set forth below is a reconciliation of the non-U.S. GAAP financial measure of Adjusted EBITDA to the U.S. GAAP financial measure of net income (loss).

	Year Ended December 31,		
	2017	2016	2015
	(Dollars in thousands)		
Net income (loss)	$5,910	$(318,634)	$(294,486)
Income tax benefit	(333,711)	(177,562)	(147,963)
Net interest expense	35,606	40,039	35,511
Depreciation, depletion, amortization and impairment	783,341	668,434	864,759
Impairment of goodwill	—	—	124,561
Adjusted EBITDA	$491,146	$212,277	$582,382

Critical Accounting Policies

In addition to established accounting policies, our consolidated financial statements are impacted by certain estimates and assumptions made by management. The following is a discussion of our critical accounting policies pertaining to property and equipment, goodwill, revenue recognition, the use of estimates and oil and natural gas properties.

Property and equipment — Property and equipment, including betterments which extend the useful life of the asset, are stated at cost. Maintenance and repairs are charged to expense when incurred. We provide for the depreciation of our property and equipment using the straight-line method over the estimated useful lives. Our method of depreciation does not change when equipment becomes idle; we continue to depreciate idled equipment on a straight-line basis. No provision for salvage value is considered in determining depreciation of our property and equipment.

On a periodic basis, we evaluate our fleet of drilling rigs for marketability based on the condition of inactive rigs, expenditures that would be necessary to bring them to working condition and the expected demand for drilling services by rig type (such as drilling conventional, vertical wells versus drilling longer, horizontal wells using higher specification rigs). The components comprising rigs that will no longer be marketed are evaluated, and those components with continuing utility to our other marketed rigs are transferred to other rigs or to our yards to be used as spare equipment. The remaining components of these rigs will be retired. In 2017, we recorded an impairment charge of $29.0 million for the write-down of drilling equipment with no continuing utility as a result of the upgrade of certain rigs to super-spec capability. In 2016, we retired 19 mechanical rigs but recorded no impairment charge as we had written down mechanical rigs that were still marketed in 2015. In 2015, we identified 24 mechanical rigs and nine non-APEX® electric rigs that would no longer be marketed. Also, we had 15 additional mechanical rigs that continued to be marketed but were not operating and which we had lower expectations with respect to utilization of these rigs due to the industry shift to higher specification drilling rigs. In 2015, we recorded a charge of $131 million related to the retirement of the 33 rigs, the 15 mechanical rigs that remained marketed but were not operating, and the write-down of excess spare rig components to their realizable values.

We also periodically evaluate our pressure pumping assets, and in 2015, we recorded a charge of $22.0 million for the write-down of pressure pumping equipment and certain closed facilities. There were no similar charges in 2017 or 2016.

We review our long-lived assets, including property and equipment, for impairment whenever events or changes in circumstances indicate that the carrying values of certain assets may not be recovered over their estimated remaining useful lives (“triggering events”). In connection with this review, assets are grouped at the lowest level at which identifiable cash flows are largely independent of other asset groupings. The cyclical nature of our industry has resulted in fluctuations in rig utilization over periods of time. Management believes that the contract drilling industry will continue to be cyclical and rig utilization will continue to fluctuate. We estimate future cash flows over the life of the respective assets or asset groupings in our assessment of impairment. These estimates of cash flows are based on historical cyclical trends in the industry as well as management’s expectations regarding the continuation of these trends in the future. Provisions for asset impairment are charged against income when estimated future cash flows, on an undiscounted basis, are less than the asset’s net book value. Any provision for impairment is measured at fair value.

Based on current commodity prices, our results of operations for the year ended December 31, 2017 and management's expectations of operating results in future periods, we concluded that no triggering events occurred during the year ended December 31, 2017 with respect to our reporting segments. Our expectations of future operating results were based on the assumption that activity levels in all segments and our other operations will remain relatively stable or improve in response to relatively stable or increasing oil prices.

We concluded that no triggering events occurred during the year ended December 31, 2016, with respect to our reporting segments, based on our results of operations for the year ended December 31, 2016, our expectations of operating results in future periods and the prevailing commodity prices at the time.

During the third quarter of 2015, oil prices declined and averaged $46.42 per barrel, reaching a new low for 2015 of $38.22 per barrel in August 2015. In light of these lower oil prices in August, we lowered our expectations with respect to future activity levels in both the contract drilling and pressure pumping businesses. As a result of these revised expectations of the duration of the lower oil and natural gas commodity price environment and the related deterioration of the markets for contract drilling and pressure pumping services during the third quarter of 2015, we concluded a triggering event had occurred and deemed it necessary to assess the recoverability of long-lived asset groups for both contract drilling and pressure pumping. We performed a Step 1 analysis to assess the recoverability of long-lived assets within our contract drilling and pressure pumping segments. With respect to these assets, future cash flows were estimated over the expected remaining life of the assets, and we determined that, on an undiscounted basis, expected cash flows exceeded the carrying value of the long-lived assets, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the long-lived assets within the contract drilling and pressure pumping segments by approximately 120% and 60%, respectively.

Due to the continued deterioration of crude oil prices in the fourth quarter of 2015, we deemed it necessary to once again assess the recoverability of long-lived assets groups for both contract drilling and pressure pumping. We performed a Step 1 analysis as required by ASC 360-10-35 to assess the recoverability of long-lived assets within our contract drilling and pressure pumping segments. With respect to these assets, future cash flows were estimated over the expected remaining life of the assets, and we determined that, on an undiscounted basis, expected cash flows exceeded the carrying value of the long-lived assets, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the long-lived assets within the contract drilling and pressure pumping segments by approximately 120% and 100%, respectively.

For both of the assessments performed in 2015, the expected cash flows for the contract drilling segment included the backlog of commitments for contract drilling revenues under term contracts, which was approximately $801 million and $710 million at September 30, 2015 and December 31, 2015, respectively. Rigs not under term contracts would be subject to pricing in the spot market. Utilization and rates for rigs in the spot market and for the pressure pumping segment were estimated based upon our historical experience in prior downturns. Also, the expected cash flows for the contract drilling and pressure pumping segments were based on the assumption that activity levels in both segments would begin to recover in the first quarter of 2017 in response to improved oil prices.

Goodwill — Goodwill is considered to have an indefinite useful economic life and is not amortized. Goodwill is evaluated at least annually as of December 31, or when circumstances require, to determine if the fair value of recorded goodwill has decreased below its carrying value. For purposes of impairment testing, goodwill is evaluated at the reporting unit level. Our reporting units for impairment testing have been determined to be our operating segments. We determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying value after considering qualitative, market and other factors, and if this is the case, any necessary goodwill impairment is determined using a quantitative impairment test. From time to time, we may perform quantitative testing for goodwill impairment in lieu of performing the qualitative assessment. If the resulting fair value of goodwill is less than the carrying value of goodwill, an impairment loss would be recognized for the amount of the shortfall.

In January 2017, the FASB issued an accounting standards update to eliminate Step 2 from the goodwill impairment test. An entity will now perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value, but the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. We adopted this update in 2017. Prior to adoption we first determined whether it was more likely than not that the fair value of a reporting unit was less than its carrying value after considering qualitative, market and other factors, and if so, the resulting goodwill impairment was determined using a two-step quantitative impairment test. The first step of the quantitative testing was to compare the fair value of an entity's reporting units to the respective carrying value of those reporting units. If the carrying value of a reporting unit exceeded its fair value, the second step of the quantitative testing was performed whereby the fair value of the reporting unit was allocated to its identifiable tangible and intangible assets and liabilities, with any remaining fair value representing the fair value of goodwill. If this resulting fair value of goodwill was less than the carrying value of goodwill, an impairment loss was recognized in the amount of such shortfall.

In connection with our annual goodwill impairment assessment as of December 31, 2017 and 2016, we determined based on an assessment of qualitative factors that it was more likely than not that the fair values of our reporting units were greater than the respective carrying amount. In making this determination, we considered the current and expected levels of commodity prices for oil and natural gas, which influence the overall level of business activity in our reporting units, as well as our operating results for 2017 and 2016 and forecasted operating results for the respective succeeding year. Management also considered our overall market capitalization at December 31, 2017 and 2016.

During the third quarter of 2015, oil prices declined and averaged $46.42 per barrel, reaching a new low for 2015 of $38.22 per barrel in August 2015. In light of these lower oil prices in August, we lowered our expectations with respect to future activity levels in both the contract drilling and pressure pumping businesses. As a result of our revised expectations of the duration of the lower oil and natural gas commodity price environment and the related deterioration of the markets for our contract drilling and pressure pumping services, we performed a quantitative Step 1 impairment assessment of our goodwill as of September 30, 2015. In completing the Step 1 assessment, the fair value of each reporting unit was estimated using both the income and market valuation methods. The estimate of the fair value of each reporting unit required the use of significant unobservable inputs, representative of a Level 3 fair value measurement. The inputs included assumptions related to the future performance of our contract drilling and pressure pumping reporting units, such as future oil and natural gas prices and projected demand for our services, and assumptions related to discount rates, long-term growth rates and control premiums.

Based on the results of the Step 1 goodwill impairment test as of September 30, 2015, the fair value of the contract drilling reporting unit exceeded its carrying value by approximately 15%, and we concluded that no impairment was indicated in our contract drilling reporting unit; however, impairment was indicated in our pressure pumping reporting unit. In the third quarter of 2015, we recognized an impairment charge of $125 million associated with the impairment of all of the goodwill in our pressure pumping reporting unit.

In connection with our annual goodwill impairment assessment as of December 31, 2015, we performed a quantitative Step 1 impairment assessment of the goodwill in our contract drilling reporting unit. In completing the Step 1 assessment, the fair value of the contract drilling reporting unit was estimated using both the income and market valuation methods. The estimate of the fair value of the reporting unit required the use of significant unobservable inputs, representative of a Level 3 fair value measurement. The inputs included assumptions related to the future performance of our contract drilling reporting unit, such as future oil and natural gas prices and projected demand for our services, and assumptions related to discount rates, long-term growth rates and control premiums. Based on the results of the quantitative Step 1 impairment assessment of our goodwill, as of December 31, 2015, the fair value of our contract drilling reporting unit exceeded its carrying value by approximately 16%, and we concluded that no impairment was indicated in our contract drilling reporting unit.

Revenue recognition — Revenues from our contract drilling, pressure pumping, directional drilling, oilfield rental and pipe handling components and related technology activities are recognized as services are performed. All of the wells we drilled in 2017, 2016 and 2015 were drilled under daywork contracts. Revenues from sales of products are recognized upon customer acceptance. Revenues are presented net of any sales tax charged to the customer that we are required to remit to local or state governmental taxing authorities.

Reimbursements for the purchase of supplies, equipment, personnel services, shipping and other services that are provided at the request of our customers are recorded as revenue when incurred. The related costs are recorded as operating expense when incurred.

Use of estimates — The preparation of financial statements in conformity with U.S. GAAP requires management to make certain estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from such estimates.

Key estimates used by management include:

- allowance for doubtful accounts,
- depreciation, depletion and amortization,
- fair values of assets acquired and liabilities assumed in acquisitions,
- goodwill and long-lived asset impairments, and
- reserves for self-insured levels of insurance coverage.

For additional information on our accounting policies, see Note 1 of Notes to Consolidated Financial Statements included as a part of Item 8 of this Report.

Volatility of Oil and Natural Gas Prices and its Impact on Operations and Financial Condition

Our revenue, profitability and cash flows are highly dependent upon prevailing prices for oil and natural gas and expectations about future prices. For many years, oil and natural gas prices and markets have been extremely volatile. Prices are affected by many factors beyond our control. Please see "Risk Factors – We are Dependent on the Oil and Natural Gas Industry and Market Prices for Oil and Natural Gas. Declines in Customers' Operating and Capital Expenditures and in Oil and Natural Gas Prices May Adversely Affect Our Operating Results" in Item 1A of this Report. The closing price of oil was as high as $107.95 per barrel in June 2014. Prices began to fall in the third quarter of 2014 and reached a twelve-year low of $26.19 in February 2016. Oil and natural gas prices have modestly recovered from the lows experienced in the first quarter of 2016. Oil prices averaged $55.37 per barrel in the fourth quarter of 2017. In response to improved prices, U.S. rig counts have increased, and we believe they will continue to increase throughout 2018 if prices for these commodities remain at or above current levels.

We expect oil and natural gas prices to continue to be volatile and to affect our financial condition, operations and ability to access sources of capital. Higher oil and natural gas prices do not necessarily result in increased activity because demand for our services is generally driven by our customers' expectations of future oil and natural gas prices. A decline in demand for oil and natural gas, prolonged low oil or natural gas prices or expectations of decreases in oil and natural gas prices, would likely result in reduced capital expenditures by our customers and decreased demand for our services, which could have a material adverse effect on our operating results, financial condition and cash flows. Even during periods of high prices for oil and natural gas, companies exploring for oil and natural gas may cancel or curtail programs, or reduce their levels of capital expenditures for exploration and production for a variety of reasons, which could reduce demand for our services.

Impact of Inflation

Inflation has not had a significant impact on our operations during the three years ended December 31, 2017. We believe that inflation will not have a significant near-term impact on our financial position.

Recently Issued Accounting Standards

For a discussion of recently issued accounting standards, see Note 1 of Notes to Consolidated Financial Statements included as a part of Item 8 of this Report.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We currently have exposure to interest rate market risk associated with any borrowings that we have under the Credit Agreement and the Reimbursement Agreement.

Loans under the Credit Agreement bear interest by reference, at our election, to the LIBOR rate or base rate, provided, that swing line loans bear interest by reference only to the base rate. Beginning September 27, 2017, the applicable margin on LIBOR rate loans varies from 3.25% to 3.75% and the applicable margin on base rate loans varies from 2.25% to 2.75%, in each case determined based on our excess availability under the revolving credit facility. As of December 31, 2017, the applicable margin on LIBOR rate loans was 3.50% and the applicable margin on base rate loans was 2.50%.

As of December 31, 2017, we had $268 million outstanding under our revolving credit facility at a weighted average interest rate of 5.71%. The interest rate on the borrowings outstanding under our revolving credit facility is variable and adjusts at each interest payment date based on our election of LIBOR or the base rate.

Under the Reimbursement Agreement, we will reimburse the issuing bank on demand for any amounts that it has disbursed under any letters of credit. We are obligated to pay to the issuing bank interest on all amounts not paid by us on the date of demand or when otherwise due at the LIBOR rate plus 2.25% per annum. As of December 31, 2017, no amounts had been disbursed under any letters of credit.

We conduct a portion of our business in Canadian dollars through our Canadian land-based drilling operations and our Canadian manufacturing subsidiary. The exchange rate between Canadian dollars and U.S. dollars has fluctuated during the last several years. If the value of the Canadian dollar against the U.S. dollar weakens, revenues and earnings of our Canadian operations will be reduced and the value of our Canadian net assets will decline when they are translated to U.S. dollars. This currency risk is not material to our results of operations or financial condition.

The carrying values of cash and cash equivalents, trade receivables and accounts payable approximate fair value due to the short-term maturity of these items.

Item 8. Financial Statements and Supplementary Data.

Financial Statements are filed as a part of this Report at the end of Part IV hereof beginning at page F-1, Index to Consolidated Financial Statements, and are incorporated herein by this reference.

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

None.

Item 9A. Controls and Procedures.

Disclosure Controls and Procedures:

Under the supervision and with the participation of our management, including our Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), we conducted an evaluation of the effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Exchange Act, as of the end of the period covered by this Report. Based on this evaluation, our CEO and CFO concluded that, as of December 31, 2017, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms and is accumulated and reported to our management, including our CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting:

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our CEO and CFO, we carried out an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2017, based on the Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, our management has concluded that our internal control over financial reporting was effective as of December 31, 2017.

Our wholly-owned subsidiary, MS Directional, LLC, was excluded from our evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2017. We acquired MS Directional, LLC on October 11, 2017. This subsidiary was excluded from the scope of our review due to the fact that the acquisition closed in the fourth quarter of 2017, at which time we began integrating the acquired business into our existing internal controls over financial reporting. The acquired business represented approximately two percent of our consolidated revenues for the year ended December 31, 2017 and approximately five percent of our consolidated total assets as of December 31, 2017.

The effectiveness of our internal control over financial reporting as of December 31, 2017 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page F-2 of this Report and which is incorporated by reference into Item 8 of this Report.

Changes in Internal Control over Financial Reporting:

There have been no changes in our internal control over financial reporting during the most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

PART III

Certain information required by Part III is omitted from this Report because we expect to file a definitive proxy statement (the “Proxy Statement”) pursuant to Regulation 14A of the Securities Exchange Act of 1934 no later than 120 days after the end of the fiscal year covered by this Report and certain information included therein is incorporated herein by reference.

Item 10. Directors, Executive Officers and Corporate Governance.

The information required by this Item is incorporated herein by reference to the Proxy Statement.

We have adopted a Code of Business Conduct and Ethics for Senior Financial Executives, which covers, among others, our principal executive officer and principal financial and accounting officer. The text of this code is located on our website under “Governance.” Our Internet address is www.patenergy.com. We intend to disclose any amendments to or waivers from this code on our website.

Item 11. Executive Compensation.

The information required by this Item is incorporated herein by reference to the Proxy Statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The information required by this Item is incorporated herein by reference to the Proxy Statement.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

The information required by this Item is incorporated herein by reference to the Proxy Statement.

Item 14. Principal Accounting Fees and Services.

The information required by this Item is incorporated herein by reference to the Proxy Statement.

PART IV

Item 15. Exhibits and Financial Statement Schedule.

(a)(1) Financial Statements

See Index to Consolidated Financial Statements on page F-1 of this Report.

(a)(2) Financial Statement Schedule

Schedule II — Valuation and qualifying accounts is filed herewith on page S-1.

All other financial statement schedules have been omitted because they are not applicable or the information required therein is included elsewhere in the financial statements or notes thereto.

(a)(3) Exhibits

The following exhibits are filed herewith or incorporated by reference herein. Our Commission file number is 0-22664.

2.1	~~Agreement and Plan of Merger by and among Patterson-UTI Energy, Inc., Pyramid Merger Sub, Inc. and Seventy Seven Energy Inc., dated as of December 12, 2016 (filed December 13, 2016 as Exhibit 2.1 to the Company's Current Report on Form 8-K and incorporated herein by reference)~~.
3.1	~~Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.1 to the Company'~~s ~~Quarterly Report on Form 10-Q and incorporated herein by reference).~~
3.2	~~Certificate of Amendment to the Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q and incorporated herein by reference~~).
3.3	~~Certificate of Elimination with respect to Series A Participating Preferred Stock (filed October 27, 2011 as Exhibit 3.1 to the Company's Current Report on Form 8-K and incorporated herein by reference~~).
3.4	~~Second Amended and Restated Bylaws (filed August 6, 2007 as Exhibit 3.3 to the Company's Quarterl~~y ~~Report on Form 10-Q and incorporated herein by reference).~~
4.1	~~Registration Rights Agreement with Bear, Stearns and Co. Inc., dated March 25, 1994, as assigned to REMY Capital Partners III, L.P. (filed March 19, 2002 as Exhibit 4.3 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2001 and incorporated herein by reference).~~
4.2	~~Registration Rights Agreement, dated as of October 11, 2017, between Patterson-UTI Energy, Inc. and the sellers party thereto.+~~
4.3	~~Base Indenture, dated January 19, 2018, among Patterson-UTI Energy, Inc., the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (filed January 19, 2018 as Exhibit 4.1 to the~~

~~Company's Current Report on Form 8-K and incorporated herein by reference)~~.

4.4 ~~First Supplemental Indenture, dated January 19, 2018, among Patterson-UTI Energy, Inc., the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (filed January 19, 2018 as Exhibit 4.2 to the Company's Current Report on Form 8-K and incorporated herein by reference)~~.

4.5 ~~Form of 3.95% Senior Note due 2028 (included in Exhibit 4.4 above).~~

4.6 ~~Registration Rights Agreement, dated January 19, 2018, among Patterson-UTI Energy, Inc., the several guarantors named therein and Goldman, Sachs & Co. LLC, Wells Fargo Securities, LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated (filed January 19, 2018 as Exhibit 4.4 to the Company's Current Repor~~t ~~on Form 8-K and incorporated herein by reference).~~

10.1 ~~Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, including Form of Executive Officer Restricted Stock Award Agreement, Form of Executive Officer Stock Option Agreement, Form of Non-Employee Director Restricted Stock Award Agreement and Form of Non-Employee Director Stock Option Agreement (filed June 21, 2005 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein b~~y ~~reference).~~*

10.2 ~~First Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed June 6, 2008 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).~~*

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10.3 ~~Second Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed June 6, 2008 as Exhibit 10.2 to the Company'~~s ~~Current Report on Form 8-K and incorporated herein by reference).~~*

10.4 ~~Third Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed April 27, 2010 as Exhibit 10.1 to the Company'~~s ~~Current Report on Form 8-K and incorporated herein by reference).~~*

10.5 ~~Fourth Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed April 27, 2010 as Exhibit 10.2 to the Company'~~s ~~Current Report~~

~~on Form 8-K and incorporated herein by reference).~~*

10.6 ~~Fifth Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed August 2, 2010 as Exhibit 10.4 to the Company'~~s ~~Quarterly Report on Form 10-Q and incorporated herein by reference).~~*

10.7 ~~Form of Share-Settled Performance Unit~~ ~~Award Agreement under the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed August 2, 2010 as Exhibit 10.5 to the Company'~~s ~~Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2010 and incorporated herein by reference).~~*

10.8

	~~Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan (filed April 21, 2014 as Exhibit 10.1 to the Company’~~s ~~Current Report on Form 8-K and incorporated herein by reference).~~*
10.9	~~Patterson-UTI Energy, Inc. Omnibus Incentive Plan (filed April 21, 2017 as Exhibit 4.4 to the Company’~~s ~~Registration Statement on Form S-8 and incorporated herein by reference)*~~
10.10	~~Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan (as amended and restated effective June 29, 2017) (filed June 30, 2017 as Exhibit 10.1 to the Company’~~s ~~Current Report on Form 8-K and incorporated herein by reference).*~~

10.11	~~Form of Executive Officer Share-Settled Performance Share Award Agreement (filed April 21, 2014 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).*~~
10.12	~~Form of Executive Officer Share-Settled Performance Share Award Agreement (filed May 2, 2016 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q and incorporated herein by reference).*~~
10.13	~~Form of Executive Officer Restricted Stock Award Agreement (filed April 21, 2014 as Exhibit 10.3 to the Company's Current Report on Form 8-K and incorporated herein by~~

~~reference).*~~

10.14 ~~Form of Executive Officer Restricted Stock Award Agreement (filed May 2, 2016 as Exhibit 10.1 to the Company'~~s ~~Quarterly Report on Form 10-Q and incorporated herein by reference).*~~

10.15 ~~Form of Executive Officer Restricted Stock Unit Award Agreement (filed August 4, 2017 as Exhibit 10.5 to the Company'~~s ~~Quarterly Report on Form 10-Q and incorporated herein by reference).*~~

10.16 ~~Form of Executive Officer Stock Option Agreement (filed April 21, 2014 as Exhibit 10.4 to the Company'~~s ~~Current Report on Form 8-K and incorporated herein by~~

	~~reference).~~*
10.17	~~Form of Non-Employee Director Restricted Stock Award Agreement (filed April 21, 2014 as Exhibit 10.5 to the Company’~~s ~~Current Report on Form 8-K and incorporated herein by reference).~~*
10.18	~~Form of Non-Employee Director Stock Option Agreement (filed April 21, 2014 as Exhibit 10.6 to the Company’~~s ~~Current Report on Form 8-K and incorporated herein by reference).~~*
10.19	~~Form of Non-Employee Director Restricted Stock Unit Award Agreement.+~~*
10.20	~~Form of Letter Agreement regarding termination, effective as of January 29, 2004, entered into by~~

~~Patterson-UTI Energy, Inc. with each of Mark S. Siegel and Kenneth N. Berns (filed on February 25, 2005 as Exhibit 10.23 to the Company'~~s ~~Annual Report on Form 10-K for the year ended December 31, 2004 and incorporated herein by reference).~~*

10.21 ~~Employment Agreement, effective as of January 1, 2017, by and between Patterson-UTI Drilling Company LLC and James M. Holcomb (filed January 17, 2017 as Exhibit 10.1 to the Company'~~s ~~Current Report on Form 8-K and incorporated herein by reference).~~ *

10.22 ~~Employment Agreement, effective as of August 1,~~ ~~2016, by and between Patterson-UTI Energy, Inc. and William Andrew~~

~~Hendricks, Jr. (filed August 2, 2016 as Exhibit 10.2 to the Company’~~s ~~Quarterly Report on Form 10-Q and incorporated herein by reference).~~ *

10.23 ~~Employment Agreement, effective as of August 1, 2016, by and between Patterson-UTI Energy, Inc. and Seth D. Wexler (filed February 13, 2017 as Exhibit 10.20 to the Company’~~s ~~Annual Report on Form 10-K for the year ended December 31, 2016 and incorporated herein by reference).~~*

10.24 ~~Employment Agreement, dated as of September 3, 2017, between Patterson-UTI Energy, Inc. and C. Andrew Smith (filed September 8, 2017 as Exhibit 10.2 to the Company’~~s ~~Current Report on Form 8-K and~~

~~incorporated herein by reference).~~*

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10.25	~~Employment Agreement, dated as of December 31, 2017, between Patterson-UTI Energy, Inc. and John E. Vollmer III (filed December 27, 2017 as Exhibit 10.1 to the Company's~~s ~~Current Report on Form 8-K and incorporated herein by reference).*~~
10.26	~~Form of Indemnification Agreement entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Kenneth N. Berns, Curtis W. Huff, Terry H. Hunt, Charles O. Buckner, John E. Vollmer III,~~ ~~Seth D. Wexler, William Andrew Hendricks, Jr., Michael W. Conlon, Tiffany J. Thom and C. Andrew Smith (filed April 28, 2004~~ ~~as Exhibit 10.11 to the Company's~~s ~~Annual Report on Form 10-K, as amended, for the year ended December 31,~~

	~~2003 and incorporated herein by reference).*~~
10.27	~~Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and Mark S. Siegel (filed on February 4, 2004 as Exhibit 10.2 to the Company'~~s ~~Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*~~
10.28	~~Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and Kenneth N. Berns (filed on February 4, 2004 as Exhibit 10.5 to the Company'~~s ~~Annual Report on Form 10-K~~

~~for the year ended December 31, 2003 and incorporated herein by reference).~~*

10.29 ~~First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Mark S. Siegel, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.8 to the Company'~~s ~~Quarterly Report on Form 10-Q and incorporated herein by reference).~~*

10.30 ~~First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Kenneth N. Berns, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.11 to the Company'~~s ~~Quarterly Report on Form 10-Q and incorporated~~

~~herein by reference).~~*

10.31 ~~Credit Agreement dated September 27, 2012, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender and each of the other letter of credit issuer and lender parties thereto (filed September 28, 2012 as Exhibit 10.1 to the Company'~~s ~~Current Report on Form 8-K and incorporated herein by reference).~~

10.32 ~~Amendment No. 1 to Credit Agreement, dated as of January 9, 2015, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender and each~~

~~of the other letter of credit issuer and lender parties thereto (filed January 12, 2015 as Exhibit 10.1 to the Company'~~s ~~Current Report on Form 8-K and incorporated herein by reference).~~

10.33 ~~Amendment No. 2 to Credit Agreement dated as of July 8, 2016, by~~ ~~and among Patterson-UTI Energy, Inc., certain subsidiaries party thereto, Wells Fargo Bank, N.A., as administrative agent, issuer of letters of credit and swing line lender and certain other lenders party thereto (filed July 12, 2016 as Exhibit 10.1 to the Company'~~s ~~Current Report on Form 8-K and incorporated herein by reference).~~

10.34 ~~Amendment No. 3 to Credit Agreement dated as of~~

~~January 17, 2017, by and among Patterson-UTI Energy, Inc., certain subsidiaries party thereto, Wells Fargo Bank, N.A., as administrative agent, issuer of letters of credit and swing line lender and certain other lenders party thereto (filed February 13, 2017 as Exhibit 10.31 to the Company'~~s ~~Annual Report on Form 10-K for the year ended December 31, 2016 and incorporated herein by reference).~~

10.35 ~~Commitment Increase Agreement, dated as of January 24, 2017, by and among Patterson-UTI Energy, Inc., certain subsidiaries party thereto, Wells Fargo Bank, N.A., as administrative agent, issuer of letters of credit and swing line lender and~~

~~certain other lenders party thereto (filed January 24, 2017 as Exhibit 10.1 to the Company'~~s ~~Current Report on Form 8-K and incorporated herein by reference).~~

10.36 ~~Amendment No. 4 to Credit Agreement, dated as of April 20, 2017, by and among Patterson-UTI Energy, Inc., certain subsidiaries of Patterson-UTI Energy, Inc. party thereto, Wells Fargo Bank, N.A., as administrative agent, issuer of letters of credit and swing line lender and the other lenders party thereto (filed April 21, 2017 as Exhibit 10.1 to the Company'~~s ~~Current Report on Form 8-K and incorporated herein by reference).~~

10.37 ~~Commitment Increase Agreement, dated as of April~~

	~~20, 2017, by and among Patterson-UTI Energy, Inc., certain subsidiaries of Patterson-UTI Energy, Inc. party thereto, Wells Fargo Bank, N.A., as administrative agent, issuer of letters of credit and swing line lender and the other lenders party thereto (filed April 21, 2017 as Exhibit 10.2 to the Company’~~s ~~Current Report on Form 8-K and incorporated herein by reference).~~
10.38	~~Commitment Increase Agreement, dated as of October 27, 2017, by and among Patterson-UTI Energy, Inc., certain subsidiaries of Patterson-UTI Energy, Inc. party~~ ~~thereto, and Wells Fargo Bank, N.A., as administrative agent, issuer of letters of credit and swing line lender (filed November 2,~~

~~2017 as Exhibit 10.3 to the Company’~~s ~~Quarterly Report on Form 10-Q and incorporated herein by reference).~~

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10.39 ~~Note Purchase Agreement dated October 5, 2010 by and among Patterson-UTI Energy, Inc. and the purchasers named therein (filed October 6, 2010 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).~~

10.40 ~~Amendment No. 1 to Note Purchase Agreement, dated as of October 22, 2015, by and among Patterson-UTI Energy, Inc., certain subsidiaries of Patterson-UTI Energy, Inc. party thereto, and the purchasers named therein (relates to Note Purchase Agreement dated October 5, 2010) (filed October 28, 2015 as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q and incorporated herein by reference)~~.

10.41 ~~Note Purchase Agreement dated June 14, 2012 by and among Patterson-UTI Energy, Inc. and the purchasers named therein (filed June 18, 2012 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).~~

10.42 ~~Amendment No. 1 to Note Purchase Agreement, dated as of October 22, 2015, by and among Patterson-UTI Energy, Inc., certain subsidiaries of Patterson-UTI Energy, Inc. party thereto, and the purchasers named therein (relates to Note Purchase Agreement dated June 14, 2012) (filed October 28, 2015 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q and incorporated herein by reference)~~.

10.43 ~~Reimbursement Agreement, dated as of March 16, 2015, by and between Patterson-UTI Energy, Inc. and The Bank of Nova Scotia (filed March 16, 2015 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).~~

10.44 ~~Continuing Guaranty, dated as of March 16, 2015, by Patterson Petroleum LLC, Patterson-UTI Drilling Company LLC, Patterson-UTI Management Services, LLC, Universal Well Services, Inc. and Universal Pressure Pumping, Inc. (filed March 16, 2015 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).~~

10.45 ~~Securities Purchase Agreement, dated as of September 4, 2017, between Patterson-UTI Energy, Inc., certain holders of limited liability company interests of Multi-Shot, LLC, and MS Incentive Plan Holdco, LLC (filed September 8, 2017 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).~~

21.1 ~~Subsidiaries of the Registrant.+~~

23.1 ~~Consent of Independent Registered Public Accounting Firm.+~~

31.1 ~~Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended.+~~

31.2 ~~Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended.~~+

32.1 ~~Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 USC Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.~~+

101 The following materials from Patterson-UTI Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2017, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Changes in Stockholders' Equity, (v) the Consolidated Statements of Cash Flows, and (vi) Notes to Consolidated Financial Statements.+

*Management Contract or Compensatory Plan identified as required by Item 15(a)(3) of Form 10-K.
+Filed herewith.

Item 16. Form 10-K Summary

None.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Patterson-UTI Energy, Inc.:

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Patterson-UTI Energy, Inc. and its subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of operations, comprehensive income (loss), changes in shareholders' equity and cash flows for each of the three years in the period ended December 31, 2017, including the related notes and financial statement schedule listed in the index appearing under Item 15(a)(2) (collectively referred to as the "Consolidated Financial Statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017 based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017 , based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it presents deferred tax assets and liabilities in 2017.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As described in Management's Report on Internal Control over Financial Reporting, management has excluded MS Directional, LLC from its assessment of internal control over financial reporting as of December 31, 2017 because it was acquired by the Company in a purchase business combination during 2017. MS Directional, LLC is a wholly-owned subsidiary whose total assets and total revenues excluded from management's assessment and our audit of internal control over financial reporting represent 5% and 2%, respectively of the related consolidated financial statement amounts as of and for the year ended December 31, 2017.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's 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 the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the 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 or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 20, 2018

We have served as the Company's auditor since 1993.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2017	2016
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$42,828	$35,152
Accounts receivable, net of allowance for doubtful accounts of $2,323 and $3,191 at December 31, 2017 and 2016, respectively	580,354	148,091
Federal and state income taxes receivable	1,152	2,126
Inventory	69,167	20,191
Other	53,354	41,322
Total current assets	746,855	246,882
Property and equipment, net	4,254,730	3,408,963
Goodwill and intangible assets	687,072	88,966
Deposits on equipment purchases	16,351	16,050
Deferred tax assets, net	3,875	4,124
Other	49,973	7,306
Total assets	$5,758,856	$3,772,291
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$319,621	$125,667
Accrued expenses	226,629	139,148
Total current liabilities	546,250	264,815
Borrowings under revolving credit facility	268,000	—
Long-term debt, net of debt issuance cost of $1,217 and $1,563 at December 31, 2017 and 2016, respectively	598,783	598,437
Deferred tax liabilities, net	350,836	650,661
Other	12,494	9,654
Total liabilities	1,776,363	1,523,567
Commitments and contingencies (see Note 8)		
Stockholders' equity:		
Preferred stock, par value $.01; authorized 1,000,000 shares, no shares issued	—	—
Common stock, par value $.01; authorized 300,000,000 shares with 266,259,083 and 191,525,872 issued and 222,456,472 and 148,133,255 outstanding at December 31, 2017 and 2016, respectively	2,662	1,915
Additional paid-in capital	2,785,823	1,042,696
Retained earnings	2,105,897	2,116,341
Accumulated other comprehensive income (loss)	6,822	(1,134)
Treasury stock, at cost, 43,802,611 shares and 43,392,617 shares at	(918,711)	(911,094)

December 31, 2017 and 2016, respectively		
Total stockholders’ equity	3,982,493	2,248,724
Total liabilities and stockholders’ equity	$5,758,856	$3,772,291

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2017	2016	2015
	(In thousands, except per share data)		
Operating revenues:			
Contract drilling	$1,040,033	$543,663	$1,153,892
Pressure pumping	1,200,311	354,070	712,454
Directional drilling	45,580	—	—
Other	70,760	18,133	24,931
Total operating revenues	2,356,684	915,866	1,891,277
Operating costs and expenses:			
Contract drilling	667,105	305,804	608,848
Pressure pumping	966,835	334,588	612,021
Directional drilling	32,172	—	—
Other	51,428	8,384	11,500
Depreciation, depletion, amortization and impairment	783,341	668,434	864,759
Impairment of goodwill	—	—	124,561
Selling, general and administrative	105,847	69,205	74,913
Merger and integration expenses	74,451	—	—
Other operating (income) expense, net	(31,957)	(14,323)	1,647
Total operating costs and expenses	2,649,222	1,372,092	2,298,249
Operating loss	(292,538)	(456,226)	(406,972)
Other income (expense):			
Interest income	1,866	327	964
Interest expense, net of amount capitalized	(37,472)	(40,366)	(36,475)
Other	343	69	34
Total other expense	(35,263)	(39,970)	(35,477)
Loss before income taxes	(327,801)	(496,196)	(442,449)
Income tax benefit	(333,711)	(177,562)	(147,963)
Net income (loss)	$5,910	$(318,634)	$(294,486)
Net income (loss) per common share:			
Basic	$0.03	$(2.18)	$(2.00)
Diluted	$0.03	$(2.18)	$(2.00)
Weighted average number of common shares outstanding:			
Basic	198,447	146,178	145,416
Diluted	199,882	146,178	145,416

Cash dividends per common share	$0.08	$0.16	$0.40

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Net income (loss)	$5,910	$(318,634)	$(294,486)
Other comprehensive income (loss), net of taxes of $0 for 2017, $0 for 2016 and $0 for 2015:			
Foreign currency translation adjustment	7,956	2,959	(10,556)
Total comprehensive income (loss)	$13,866	$(315,675)	$(305,042)

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Common Stock Number of Shares	Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total
	(In thousands)						
Balance, December 31, 2014	189,263	$ 1,893	$ 984,674	$ 2,811,815	$ 6,463	$ (899,035)	$ 2,905,810
Net loss	—	—	—	(294,486)	—	—	(294,486)
Foreign currency translation adjustment	—	—	—	—	(10,556)	—	(10,556)
Issuance of restricted stock	1,180	12	(12)	—	—	—	—
Vesting of restricted stock units	14	—	—	—	—	—	—
Forfeitures of restricted stock	(82)	(1)	1	—	—	—	—
Stock-based compensation	—	—	28,510	—	—	—	28,510
Tax expense related to stock-based compensation	—	—	(1,362)	—	—	—	(1,362)
Payment of cash dividends	—	—	—	(58,775)	—	—	(58,775)
Purchase of treasury stock	—	—	—	—	—	(8,010)	(8,010)
Balance, December 31, 2015	190,375	1,904	1,011,811	2,458,554	(4,093)	(907,045)	2,561,131
Net loss	—	—	—	(318,634)	—	—	(318,634)
Foreign currency translation adjustment	—	—	—	—	2,959	—	2,959
Shares issued for acquisition	354	3	6,730	—	—	—	6,733
Issuance of restricted stock	785	8	(8)	—	—	—	—
Vesting of restricted stock units	15	—	—	—	—	—	—
Forfeitures of restricted stock	(43)	—	—	—	—	—	—
Exercise of stock options	40	—	707	—	—	—	707
Stock-based compensation	—	—	28,324	—	—	—	28,324
Tax expense related to stock-based compensation	—	—	(4,868)	—	—	—	(4,868)
Payment of cash dividends	—	—	—	(23,579)	—	—	(23,579)
Purchase of treasury stock	—	—	—	—	—	(4,049)	(4,049)
	191,526	1,915	1,042,696	2,116,341	(1,134)	(911,094)	2,248,724

Balance, December 31, 2016							
Net income	—	—	—	5,910	—	—	5,910
Foreign currency translation adjustment	—	—	—	—	7,956	—	7,956
Equity offering	18,170	182	471,388	—	—	—	471,570
Shares issued for acquisitions	55,097	551	1,226,339	—	—	—	1,226,890
Issuance of restricted stock	891	9	(9)	—	—	—	—
Vesting of restricted stock units	549	5	(5)	—	—	—	—
Forfeitures of restricted stock	(24)	—	—	—	—	—	—
Exercise of stock options	50	—	931	—	—	—	931
Stock-based compensation	—	—	44,483	—	—	—	44,483
Payment of cash dividends	—	—	—	(16,315)	—	—	(16,315)
Dividend equivalents	—	—	—	(39)	—	—	(39)
Purchase of treasury stock	—	—	—	—	—	(7,617)	(7,617)
Balance, December 31, 2017	266,259	$ 2,662	$ 2,785,823	$ 2,105,897	$ 6,822	$ (918,711)	$ 3,982,493

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Cash flows from operating activities:			
Net income (loss)	$5,910	$(318,634)	$(294,486)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and impairment	783,341	668,434	864,759
Impairment of goodwill	—	—	124,561
Dry holes and abandonments	1,929	58	1,224
Deferred income tax benefit	(330,346)	(152,160)	(99,873)
Stock-based compensation expense	44,483	28,324	28,510
Net gain on asset disposals	(33,510)	(14,771)	(10,613)
Tax expense related to stock-based compensation	—	(4,868)	(1,362)
Amortization of debt issuance costs	346	2,270	1,245
Changes in operating assets and liabilities:			
Accounts receivable	(239,482)	72,327	440,884
Income taxes receivable/payable	990	30,379	49,895
Inventory and other assets	(23,449)	5,664	38,993
Accounts payable	104,072	12,024	(131,649)
Accrued expenses	(14,190)	(24,573)	(10,303)
Other liabilities	617	560	(2,348)
Net cash provided by operating activities	300,711	305,034	999,437
Cash flows from investing activities:			
Acquisitions, net of cash acquired	(501,954)	155	—
Purchases of property and equipment	(567,087)	(119,799)	(743,776)
Proceeds from disposal of assets	60,945	21,889	20,814
Other investments	(2,520)	—	—
Net cash used in investing activities	(1,010,616)	(97,755)	(722,962)
Cash flows from financing activities:			
Proceeds from equity offering	471,570	—	—
Purchases of treasury stock	(6,809)	(3,610)	(8,010)
Dividends paid	(16,315)	(23,579)	(58,775)
Proceeds from long-term debt	—	—	200,000
Repayment of long-term debt	—	(255,000)	(27,500)
Proceeds from borrowings under revolving credit facility	599,000	200,500	54,000
Repayment of borrowings under revolving credit facility	(331,000)	(200,500)	(357,000)
Debt issuance costs	—	(3,357)	(1,979)
Proceeds from exercise of stock options	123	268	—
Net cash provided by (used in) financing activities	716,569	(285,278)	(199,264)
Effect of foreign exchange rate changes on cash	1,012	(195)	(6,877)
Net increase (decrease) in cash and cash equivalents	7,676	(78,194)	70,334
Cash and cash equivalents at beginning of year	35,152	113,346	43,012
Cash and cash equivalents at end of year	$42,828	$35,152	$113,346

Supplemental disclosure of cash flow information:			
Net cash (paid) received during the year for:			
Interest, net of capitalized interest of $1,175 in 2017, $398 in 2016 and $6,332 in 2015	$(34,953)	$(36,551)	$(33,452)
Income taxes	3,947	52,716	97,333
Non-cash investing and financing activities:			
Net increase (decrease) in payables for purchases of property and equipment	$17,228	$28,926	$(167,308)
Issuance of common stock for business acquisition	1,226,890	6,733	—
Net decrease (increase) in deposits on equipment purchases	(301)	6,317	90,012

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Business and Summary of Significant Accounting Policies

A description of the business and basis of presentation follows:

Description of business — Patterson-UTI Energy, Inc., through its wholly-owned subsidiaries (collectively referred to herein as “Patterson-UTI” or the “Company”), provides onshore contract drilling services to oil and natural gas operators in the continental United States and western Canada. The Company provides pressure pumping services to oil and natural gas operators primarily in Texas and the Mid-Continent and Appalachian regions. The Company provides directional drilling services in most major producing onshore oil and gas basins in the United States. The Company also provides oilfield rental equipment in many of the major producing onshore oil and gas basins in the United States and manufactures and sells pipe handling components and related technology to drilling contractors in North America and other select markets. In addition, the Company owns and invests, as a non-operating working interest owner, in oil and natural gas assets that are primarily located in Texas and New Mexico.

Basis of presentation — The consolidated financial statements include the accounts of Patterson-UTI and its wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated. Except for wholly-owned subsidiaries, the Company has no controlling financial interests in any other entity which would require consolidation.

The U.S. dollar is the functional currency for all of the Company’s operations except for its Canadian subsidiaries, which use the Canadian dollar as their functional currency. The effects of exchange rate changes are reflected in accumulated other comprehensive income, which is a separate component of stockholders’ equity.

In 2017, the Company adopted new guidance for the presentation of deferred tax liabilities and assets and such guidance was applied retrospectively, resulting in the reclassification of $36.4 million from current deferred tax assets as of December 31, 2016. Of this amount, $4.1 million was reclassified to long-term deferred tax assets and $32.3 million was reclassified to long-term deferred tax liabilities. During 2016, the Company determined that certain income and expense items should be classified as “other operating (income) expense, net” in the consolidated statements of operations. This caption now includes gains and losses on asset disposals and expenses related to certain legal settlements. Gains and losses on asset disposals were previously presented as a separate line in the consolidated statements of operations. Expenses related to certain legal settlements were previously included in operating costs of the respective operating segment or within selling, general and administrative expense. For comparative purposes, all such prior period amounts were reclassified to conform to the current presentation, including the Company’s previously disclosed $12.3 million legal settlement that was previously included within selling, general and administrative expense for the year ended December 31, 2015. In addition, the Company changed its reporting segment presentation in 2016, as the Company no longer considers its oil and natural gas exploration and production activities to be significant to an understanding of the Company’s results. The Company now presents the oil and natural gas exploration and production activities, oilfield rental business, pipe handling components and related technology business and Middle East/North Africa activities as “Other” and “Corporate” reflects only corporate activities. This change in segment presentation was applied retrospectively to all periods presented herein (See Note 14).

On December 12, 2016, the Company entered into an Agreement and Plan of Merger (the "merger agreement") with Seventy Seven Energy Inc. ("SSE"), and the merger closed on April 20, 2017 (the "merger date"). The Company's results include the results of operations of SSE since the merger date (See Note 2). On October 11, 2017, the Company acquired all of the issued and outstanding limited liability company interests of MS Directional, LLC (f/k/a Multi-Shot, LLC) ("MS Directional"). The Company's results include the results of operations of MS Directional since October 11, 2017 (See Note 2). The acquisition of MS Directional created a new directional drilling reporting segment for the Company (See Note 14).

A summary of the significant accounting policies follows:

Management estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America ("U.S. GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from such estimates.

Revenue recognition — Revenues from our contract drilling, pressure pumping, directional drilling, oilfield rental and pipe handling components and related technology activities are recognized as services are performed. All of the wells the Company drilled in 2017, 2016 and 2015 were drilled under daywork contracts. Revenue from sales of products are recognized upon customer acceptance. Revenue is presented net of any sales tax charged to the customer that the Company is required to remit to local or state governmental taxing authorities.

Reimbursements for the purchase of supplies, equipment, personnel services, shipping and other services that are provided at the request of the Company's customers are recorded as revenue when incurred. The related costs are recorded as operating expenses when incurred.

Accounts receivable — Trade accounts receivable are recorded at the invoiced amount. The allowance for doubtful accounts represents the Company's estimate of the amount of probable credit losses existing in the Company's accounts receivable. The Company reviews the adequacy of its allowance for doubtful accounts at least quarterly. Significant individual accounts receivable balances and balances which have been outstanding greater than 90 days are reviewed individually for collectability. Account balances, when determined to be uncollectable, are charged against the allowance.

Inventories — Inventories consist primarily of sand and other products to be used in conjunction with the Company's pressure pumping activities and materials used in its directional drilling and drilling technology business. Such inventories are stated at the lower of cost or market, with cost determined using the average cost method.

Other current assets — Other current assets includes reimbursement from the Company's workers compensation insurance carrier for claims in excess of the Company's deductible in the amount of $30.0 million and $21.1 million at December 31, 2017 and 2016, respectively.

Property and equipment — Property and equipment is carried at cost less accumulated depreciation. Depreciation is provided on the straight-line method over the estimated useful lives. The method of depreciation does not change whenever equipment becomes idle. The estimated useful lives, in years, are shown below:

	Useful Lives
Equipment	1.25-15
Buildings	15-20
Other	3-12

Long-lived assets, including property and equipment, are evaluated for impairment when certain triggering events or changes in circumstances indicate that the carrying values may not be recoverable over their estimated remaining useful life.

Maintenance and repairs — Maintenance and repairs are charged to expense when incurred. Renewals and betterments which extend the life or improve existing property and equipment are capitalized.

Disposals — Upon disposition of property and equipment, the cost and related accumulated depreciation are removed and any resulting gain or loss is reflected in the consolidated statement of operations.

Oil and natural gas properties — Working interests in oil and natural gas properties are accounted for using the successful efforts method of accounting. Under the successful efforts method of accounting, exploration costs which result in the discovery of oil and natural gas reserves and all development costs are capitalized to the appropriate well. Exploration costs which do not result in discovering oil and natural gas reserves are charged to expense when such determination is made. Costs of exploratory wells are initially capitalized to wells-in-progress until the outcome of the drilling is known. The Company reviews wells-in-progress quarterly to determine whether sufficient progress is being made in assessing the reserves and economic viability of the respective projects. If no progress has been made in assessing the reserves and economic viability of a project after one year following the completion of drilling, the Company considers the well costs to be impaired and recognizes the costs as expense. Geological and geophysical costs, including seismic costs, and costs to carry and retain undeveloped properties are charged to expense when incurred. The capitalized costs of both developmental and successful exploratory type wells, consisting of lease and well equipment and intangible development costs, are depreciated, depleted and amortized using the units-of-production method, based on engineering estimates of total proved developed oil and natural gas reserves for each respective field. Oil and natural gas leasehold acquisition costs are depreciated, depleted and amortized using the units-of-production method, based on engineering estimates of total proved oil and natural gas reserves for each respective field.

The Company reviews its proved oil and natural gas properties for impairment whenever a triggering event occurs, such as downward revisions in reserve estimates or decreases in expected future oil and natural gas prices. Proved properties are grouped by field and undiscounted cash flow estimates are prepared based on management's expectation of future pricing over the lives of the respective fields. These cash flow estimates are reviewed by an independent petroleum engineer. If the net book value of a field exceeds its undiscounted cash flow estimate, impairment expense is measured and recognized as the difference between net book value and fair value. The fair value estimates used in measuring impairment are based on internally developed unobservable inputs including reserve volumes and future production, pricing and operating costs (Level 3 inputs in the fair value hierarchy of fair value accounting). The Company reviews unproved oil and natural gas properties quarterly to assess potential impairment. The Company's impairment assessment is made on a lease-by-lease basis and considers factors such as management's intent to drill, lease terms and abandonment of an area. If an unproved property is determined to be impaired, the related property costs are expensed.

Goodwill — Goodwill is considered to have an indefinite useful economic life and is not amortized. The Company assesses impairment of its goodwill at least annually as of December 31, or on an interim basis if events or circumstances indicate that the fair value of goodwill may have decreased below its carrying value.

Net income (loss) per common share — The Company provides a dual presentation of its net income (loss) per common share in its consolidated statements of operations: Basic net income (loss) per common share ("Basic EPS") and diluted net income (loss) per common share ("Diluted EPS").

Basic EPS excludes dilution and is computed by first allocating earnings between common stockholders and holders of non-vested shares of restricted stock. Basic EPS is then determined by dividing the earnings attributable to common stockholders by the weighted average number of common shares outstanding during the period, excluding non-vested shares of restricted stock.

Diluted EPS is based on the weighted average number of common shares outstanding plus the dilutive effect of potential common shares, including stock options, non-vested shares of restricted stock and restricted stock units. The dilutive effect of stock options and restricted stock units is determined using the treasury stock method. The dilutive effect of non-vested shares of restricted stock is based on the more dilutive of the treasury stock method or the two-class method, assuming a reallocation of undistributed earnings to common stockholders after considering the dilutive effect of potential common shares other than non-vested shares of restricted stock.

The following table presents information necessary to calculate net income (loss) per share for the years ended December 31, 2017, 2016 and 2015, as well as potentially dilutive securities excluded from the weighted average number of diluted common shares outstanding because their inclusion would have been anti-dilutive (in thousands, except per share amounts):

	2017	2016	2015
BASIC EPS:			
Net income (loss)	$5,910	$(318,634)	$(294,486)
Adjust for (income) loss attributed to holders of non-vested restricted stock	(170)	—	3,022
Income (loss) attributed to common stockholders	$5,740	$(318,634)	$(291,464)
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	198,447	146,178	145,416
Basic net income (loss) per common share	$0.03	$(2.18)	$(2.00)
DILUTED EPS:			
Income (loss) attributed to common stockholders	$5,740	$(318,634)	$(291,464)
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	198,447	146,178	145,416
Add dilutive effect of potential common shares	1,435	—	—
Weighted average number of diluted common shares outstanding	199,882	146,178	145,416
Diluted net income (loss) per common share	$0.03	$(2.18)	$(2.00)
Potentially dilutive securities excluded as anti-dilutive	3,289	9,057	7,781

Income taxes — The asset and liability method is used in accounting for income taxes. Under this method, deferred tax assets and liabilities are recognized for operating loss and tax credit carryforwards and for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the results of operations in the period that includes the enactment date. If applicable, a valuation allowance is recorded to reduce the carrying amounts of deferred tax assets unless it is more likely than not that such assets will be realized. The Company’s policy is to account for interest and penalties with respect to income taxes as operating expenses.

On December 22, 2017, significant changes were enacted to U.S. tax law ("tax reform"). One of the provisions of tax reform is the introduction of a new U.S. tax on certain off-shore earnings referred to as Global Intangible Low-Taxed Income ("GILTI") at an effective tax rate of 10.5% (in the case of a corporation) for tax years beginning after December 31, 2017 (increasing to 13.125% for tax years beginning after December 31, 2025) with a partial offset for any related foreign tax credits. The Company is still evaluating the GILTI provisions of tax reform and its impact, if any, on the Company's consolidated financial statements at December 31, 2017. The Financial Accounting Standards Board ("FASB") staff allowed companies to adopt an accounting policy to either provide deferred taxes for GILTI or treat it as a tax cost in the year incurred. The Company has not yet determined its accounting policy because determining the impact of the GILTI provisions requires analysis of its existing legal entity structure, the reversal of its U.S. GAAP and U.S. tax basis differences in the assets and liabilities of its foreign subsidiaries, and its ability to offset any tax with foreign tax credits. As such, the Company did not record a deferred income tax expense or benefit related to the GILTI provisions in its consolidated statement of operations for the year ended December 31, 2017 and will finalize its evaluation of the GILTI provisions during the measurement period provided under Staff Accounting Bulletin ("SAB") 118.

Stock-based compensation — The Company recognizes the cost of share-based payments under the fair-value-based method. Under this method, compensation cost related to share-based payments is measured based on the estimated fair value of the awards at the date of grant, net of estimated forfeitures. This expense is recognized over the expected life of the awards (See Note 10).

As share-based compensation expense recognized in the consolidated statements of operations is based on awards ultimately expected to vest, it has been reduced for estimated forfeitures, based on historical experience. Forfeitures are estimated at the time of grant and revised in subsequent periods if actual forfeitures differ from those estimates.

Statement of cash flows — For purposes of reporting cash flows, cash and cash equivalents include cash on deposit and money market funds.

Recently Issued Accounting Standards — In May 2014, the FASB issued an accounting standards update to provide guidance on the recognition of revenue from customers. Under this guidance, an entity will recognize revenue when it transfers promised goods or services to customers in an amount that reflects what it expects in exchange for the goods or services. This guidance also requires more detailed disclosures to enable users of the financial statements to understand the nature, amount, timing and uncertainty, if any, of revenue and cash flows arising from contracts with customers. The requirements in this update are effective during interim and annual periods beginning after December 15, 2017. The Company adopted this new revenue guidance effective January 1, 2018, utilizing the modified retrospective method, and will expand its consolidated financial statement disclosures in order to comply with the update. The adoption of this update did not have a material impact on the Company's consolidated financial statements.

In February 2016, the FASB issued an accounting standards update to provide guidance for the accounting for leasing transactions. The standard requires the lessee to recognize a lease liability along with a right-of-use asset for all leases with a term longer than one year. A lessee is permitted to make an accounting policy election by class of underlying asset to not recognize the lease liability and related right-of-use asset for leases with a term of one year or less. The provisions of this standard also apply to situations where the Company is the lessor. The requirements in this update are effective during interim and annual periods beginning after December 15, 2018. The Company previously disclosed its intention to adopt this standard at the same time as it adopted the new revenue standard discussed above; however, the Company now expects to adopt this new guidance in the first quarter of 2019. The Company is currently evaluating the impact that this new guidance will have on its consolidated financial statements.

In November 2015, the FASB issued an accounting standards update to provide guidance for the presentation of deferred tax liabilities and assets. Under this guidance, for a particular tax-paying component of an entity and within a particular tax jurisdiction, all deferred tax liabilities and assets, as well as any related valuation allowance, shall be offset and presented as a single noncurrent amount. This guidance became effective for the Company during the three months ended March 31, 2017. The adoption of this update was applied retrospectively, resulting in the reclassification of $36.4 million from current deferred tax assets as of December 31, 2016. Of this amount, $4.1 million was reclassified to long-term deferred tax assets and $32.3 million was reclassified to long-term deferred tax liabilities.

In March 2016, the FASB issued an accounting standards update to provide guidance for the accounting for share-based payment transactions, including the related income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. This guidance became effective for the Company during the three months ended March 31, 2017. The Company believes this guidance has caused and will continue to cause volatility in its effective tax rates and diluted earnings per share due to the tax effects related to share-based payments being recorded in the statement of operations. The volatility in future periods will depend on the Company's stock price and the number of shares that vest in the case of restricted stock, restricted stock units and performance stock units, or the number of shares that are exercised in the case of stock options.

In August 2016, the FASB issued an accounting standard to clarify the presentation of cash receipts and payments in specific situations on the statement of cash flows. The requirements in this update are effective during interim and annual periods beginning after December 15, 2017. The adoption of this update on January 1, 2018 did not have a material impact on the Company's consolidated financial statements.

In January 2017, the FASB issued an accounting standards update to eliminate Step 2 from the goodwill impairment test. An entity will now perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value, but the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. The requirements in this update are effective during interim and annual periods in fiscal years beginning after December 15, 2019. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates on or after January 1, 2017. The Company adopted this update in 2017, which did not have a material impact on the Company's consolidated financial statements.

In May 2017, the FASB issued an accounting standards update that provided clarity on which changes to the terms or conditions of share-based payment awards require an entity to apply modification accounting provisions. The requirements in this update are effective during interim and annual periods in fiscal years beginning after December 15, 2017. The adoption of this update on January 1, 2018 did not have a material impact on the Company's consolidated financial statements.

2. Acquisitions

SSE

On April 20, 2017, pursuant to the merger agreement, a subsidiary of the Company was merged with and into SSE, with SSE continuing as the surviving entity and one of the Company's wholly owned subsidiaries (the "SSE merger"). Pursuant to the terms of the merger agreement, the Company acquired all of the issued and outstanding shares of common stock of SSE, in exchange for approximately 46.3 million shares of common stock of the Company. Concurrent with the closing of the merger, the Company repaid all of the outstanding debt of SSE totaling $472 million. Based on the closing price of the Company's common stock on April 20, 2017, the total fair value of the consideration transferred to effect the acquisition of SSE was approximately $1.5 billion. On April 20, 2017, following the SSE merger, SSE was merged with and into a newly-formed subsidiary of the Company named Seventy Seven Energy LLC ("SSE LLC"), with SSE LLC continuing as the surviving entity and one of the Company's wholly owned subsidiaries.

Through the SSE merger, the Company acquired a fleet of 91 drilling rigs, 36 of which the Company considers to be APEX® rigs. Additionally, through the SSE merger, the Company acquired approximately 500,000 horsepower of modern, efficient fracturing equipment. The oilfield rentals business acquired through the SSE merger has a modern, well-maintained fleet of premium rental tools, and it provides specialized services for land-based oil and natural gas drilling, completion and workover activities.

The merger has been accounted for as a business combination using the acquisition method. Under the acquisition method of accounting, the fair value of the consideration transferred is allocated to the tangible and intangible assets acquired and the liabilities assumed based on their estimated fair values as of the acquisition date, with the remaining unallocated amount recorded as goodwill. Merger and integration expenses incurred by the Company related to the SSE merger were $69.5 million.

The total fair value of the consideration transferred was determined as follows (in thousands, except stock price):

Shares of Company common stock issued to SSE shareholders	46,298
Company common stock price on April 20, 2017	$22.45
Fair value of common stock issued	$1,039,396

Plus SSE long-term debt repaid by Company	$472,000
Total fair value of consideration transferred	$1,511,396

The final determination of the fair value of assets acquired and liabilities assumed at the merger date will be completed as soon as possible, but no later than one year from the merger date (the "measurement period"). The Company's preliminary purchase price allocation is subject to revision as additional information about the fair value of assets and liabilities becomes available. Additional information that existed as of the merger date, but at the time was unknown to the Company, may become known to the Company during the remainder of the measurement period. The final determination of fair value may differ materially from these preliminary estimates. The following table represents the preliminary allocation of the total purchase price of SSE to the assets acquired and the liabilities assumed based on the fair value at the merger date, with the excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill (in thousands):

Identifiable assets acquired		
Cash and cash equivalents	$	37,806
Accounts receivable		149,659
Inventory		8,518
Other current assets		19,038
Property and equipment		984,433
Other long-term assets		20,918
Intangible assets		22,500
Total identifiable assets acquired		1,242,872
Liabilities assumed		
Accounts payable and accrued liabilities		133,415
Deferred income taxes		32,881
Other long-term liabilities		1,734
Total liabilities assumed		168,030
Net identifiable assets acquired		1,074,842
Goodwill		436,554
Total net assets acquired	$	1,511,396

The goodwill reflected above has decreased $1.9 million from the original preliminary purchase price allocation as a result of measurement period adjustments, primarily related to a valuation adjustment to a long-term asset offset by valuation adjustments to accounts payable and accrued liabilities and deferred income taxes.

The acquired goodwill is not deductible for tax purposes. Among the factors that contributed to a purchase price resulting in the recognition of goodwill was SSE's reputation as an experienced provider of high-quality contract drilling and pressure pumping services in a safe and efficient manner. See Note 5 for a breakdown of goodwill acquired by operating segment.

A portion of the fair value consideration transferred has been provisionally assigned to identifiable intangible assets as follows:

	Fair Value (in thousands)	Weighted Average Useful Life (in years)
Assets		
Favorable drilling contracts	$ 22,500	0.83

MS Directional

On October 11, 2017, the Company acquired all of the issued and outstanding limited liability company interests of MS Directional. The aggregate consideration paid by the Company consisted of $69.8 million in cash and approximately 8.8 million shares of the Company's common stock. The purchase price is subject to customary post-closing adjustments relating to cash, net working capital and indebtedness of MS Directional as of the closing. Based on the closing price of the Company's common stock on the closing date of the transaction, the total fair value of the consideration transferred to effect the acquisition of MS Directional was approximately $257 million.

MS Directional is a leading directional drilling services company in the United States, with operations in most major producing onshore oil and gas basins. MS Directional provides a comprehensive suite of directional drilling services, including directional drilling, downhole performance motors, directional surveying, measurement while drilling, and wireline steering tools.

The acquisition has been accounted for as a business combination using the acquisition method. Under the acquisition method of accounting, the fair value of the consideration transferred is allocated to the tangible and intangible assets acquired and the liabilities assumed based on their estimated fair values as of the acquisition date, with the remaining unallocated amount recorded as goodwill. Merger and integration expenses incurred by the Company related to this acquisition amounted to $5.0 million.

The total fair value of the consideration transferred was determined as follows (in thousands, except stock price):

Shares of Company common stock issued to MS Directional shareholders	8,798
Company common stock price on October 11, 2017	$21.31
Fair value of common stock issued	$187,494
Plus MS Directional long-term debt repaid by Company	$63,000
Plus cash to sellers	$6,781
Total fair value of consideration transferred	$257,275

The final determination of the fair value of assets acquired and liabilities assumed at the acquisition date will be completed as soon as possible, but no later than one year from the acquisition date (the "measurement period"). The Company's preliminary purchase price allocation is subject to revision as additional information about the fair value of assets and liabilities becomes available. Additional information that existed as of the acquisition date, but at the time was unknown to the Company, may become known to the Company during the remainder of the measurement period. The final determination of fair value may differ materially from these preliminary estimates. The following table represents the preliminary allocation of the total purchase price of MS Directional to the assets acquired and the liabilities assumed based on the fair value at the merger date, with the excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill (in thousands):

Identifiable assets acquired	
Cash and cash equivalents	$2,021
Accounts receivable	42,782
Inventory	28,060
Other current assets	155
Property and equipment	63,998
Other long-term assets	318
Intangible assets	74,682
Total identifiable assets acquired	212,016
Liabilities assumed	
Accounts payable and accrued liabilities	43,099
Other long-term liabilities	327
Total liabilities assumed	43,426
Net identifiable assets acquired	168,590
Goodwill	88,685
Total net assets acquired	$257,275

The acquired goodwill is deductible for tax purposes. Among the factors that contributed to a purchase price resulting in the recognition of goodwill was MS Directional's reputation as an experienced provider of high-quality directional drilling services in a safe and efficient manner. All of the goodwill acquired is attributable to the direction drilling operating segment (See Note 5).

A portion of the fair value consideration transferred has been provisionally assigned to identifiable intangible assets as follows:

	Fair Value (in thousands)	Weighted Average Useful Life (in years)
Assets		
Developed technology	$ 48,000	10.00
Customer relationships	26,200	3.00

Internal use software	482	5.00
	$ 74,682	7.51

Pro Forma

The results of SSE’s operations since the SSE merger date of April 20, 2017 and the results of MS Directional since the acquisition date of October 11, 2017 are included in our consolidated statement of operations. It is impractical to quantify the contribution of the SSE operations since the merger, as the contract drilling and pressure pumping businesses were fully integrated into the Company’s existing operations in 2017. The contribution of MS Directional since the date of the acquisition is reflected as the Company’s directional drilling segment, as disclosed in Note 14. The following pro forma condensed combined financial information was derived from the historical financial statements of the Company, SSE and MS Directional and gives effect to the acquisitions as if they had occurred on January 1, 2016. The below information reflects pro forma adjustments based on available information and certain assumptions the Company believes are reasonable, including (i) adjustments related to the depreciation and amortization of the fair value of acquired intangibles and fixed assets, (ii) removal of the historical interest expense of the acquired entities, (iii) the tax benefit of the aforementioned pro forma adjustments, and (iv) adjustments related to the common shares outstanding to reflect the impact of the consideration exchanged in the acquisitions. Additionally, the pro forma loss for the year ended December 31, 2017 was adjusted to exclude the Company’s merger and integration-related costs of $74.5 million and SSE’s merger related costs of $36.7 million with a corresponding inclusion in the net loss for the year ended December 31, 2016 to give effect as if the acquisitions had occurred on January 1, 2016. The pro forma results of operations do not include any cost savings or other synergies that may result from the SSE merger or MS Directional acquisition. The pro forma results of operations also do not include any estimated costs that have been or will be incurred by the Company to integrate the SSE and MS Directional operations. The pro forma condensed combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have actually occurred had the SSE merger and MS Directional acquisition taken place on January 1, 2016; furthermore, the financial information is not intended to be a projection of future results. The following table summarizes selected financial information of the Company on a pro forma basis (in thousands, except per share data):

	2017	2016
	(Unaudited)	
Revenues	$2,738,579	$1,567,141
Net income (loss)	$29,584	$(505,413)
Net income (loss) per share		
Basic	$0.13	$(2.30)
Diluted	$0.13	$(2.30)

Warrior Rig Ltd

During September 2016, the Company issued 353,804 shares of its common stock, valued at $6.7 million, in connection with the acquisition of Warrior Rig Ltd. and certain related entities (“Warrior”). Based in Calgary, Warrior manufactures and sells pipe handling components and related technology for drilling contractors in North America and other select markets. This acquisition was not material to the Company’s consolidated financial statements.

3. Inventory

Inventory consisted of the following at December 31, 2017 and 2016 (in thousands).

	2017	2016
Finished goods	$2,270	$—
Work-in-process	529	1,803
Raw materials and supplies	66,368	18,388
Inventory	$69,167	$20,191

4. Property and Equipment

Property and equipment consisted of the following at December 31, 2017 and 2016 (in thousands):

	2017	2016
Equipment	$8,066,404	$6,809,129
Oil and natural gas properties	211,566	201,568
Buildings	185,475	97,029
Land	26,593	22,270
Total property and equipment	8,490,038	7,129,996
Less accumulated depreciation, depletion and impairment	(4,235,308)	(3,721,033)
Property and equipment, net	$4,254,730	$3,408,963

Depreciation, depletion, amortization and impairment — The following table summarizes depreciation, depletion, amortization and impairment expense related to property and equipment and intangible assets and liabilities for 2017, 2016 and 2015 (in thousands):

	2017	2016	2015
Depreciation and impairment expense	$753,510	$657,571	$845,543
Amortization expense	21,764	3,643	3,643
Depletion expense	8,067	7,220	15,573
Total	$783,341	$668,434	$864,759

On a periodic basis, the Company evaluates its fleet of drilling rigs for marketability based on the condition of inactive rigs, expenditures that would be necessary to bring them to working condition and the expected demand for drilling services by rig type (such as drilling conventional, vertical wells versus drilling longer, horizontal wells using higher specification rigs). The components comprising rigs that will no longer be marketed are evaluated, and those components with continuing utility to the Company's other marketed rigs are transferred to other rigs or to the Company's yards to be used as spare equipment. The remaining components of these rigs are retired. In 2017, the Company recorded an impairment charge of $29.0 million for the write-down of drilling equipment with no continuing utility as a result of the upgrade of certain rigs to super-spec capability. In 2016, the Company retired 19 mechanical rigs but recorded no impairment charge as it had written down mechanical rigs that were still marketed in 2015. In 2015, the Company identified 24 mechanical rigs and nine non-APEX® electric rigs that would no longer be marketed. Also, the Company had 15 additional mechanical rigs that continued to be marketed but were not operating and which the Company had lower expectations with respect to utilization of these rigs due to the industry shift to higher specification drilling rigs. In 2015, the Company recorded a charge of $131 million related to the retirement of the 33 rigs, the 15 mechanical rigs that remained marketed but were not operating, and the write-down of excess spare rig components to their realizable values.

The Company also periodically evaluates its pressure pumping assets, and in 2015, the Company recorded a charge of $22.0 million for the write-down of pressure pumping equipment and certain closed facilities. There were no similar charges in 2017 or 2016.

The Company reviews its long-lived assets, including property and equipment, for impairment whenever events or changes in circumstances indicate that their carrying amounts of certain assets may not be recovered over their estimated remaining useful lives ("triggering events"). In connection with this review, assets are grouped at the lowest level at which identifiable cash flows are largely independent of other asset groupings. The Company estimates future cash flows over the life of the respective assets or asset groupings in its assessment of impairment. These estimates of cash flows are based on historical cyclical trends in the industry as well as the Company's expectations regarding the continuation of these trends in the future. Provisions for asset impairment are charged against income when estimated future cash flows, on an undiscounted basis, are less than the asset's net book value. Any provision for impairment is measured at fair value.

Based on current commodity prices, the Company's results of operations for the year ended December 31, 2017 and management's expectations of operating results in future periods, the Company concluded that no triggering events occurred during the year ended December 31, 2017 with respect to its reporting segments. The Company's expectations of future operating results were based on the assumption that activity levels in all segments and in the Company's other operations will remain relatively stable or improve in response to relatively stable or increasing oil prices.

The Company concluded that no triggering events occurred during the year ended December 31, 2016 with respect to its reporting segments based on the Company's results of operations for the year ended December 31, 2016, management's expectations of operating results in future periods and the prevailing commodity prices at the time.

During the third quarter of 2015, oil prices declined and averaged $46.42 per barrel, reaching a new low for 2015 of $38.22 per barrel in August 2015. In light of these lower oil prices in August 2015, the Company lowered its expectations with respect to future activity levels in both the contract drilling and pressure pumping businesses. As a result of these revised expectations of the duration of the lower oil and natural gas commodity price environment and the related deterioration of the markets for contract drilling and pressure pumping services during the third quarter of 2015, management concluded a triggering event had occurred and deemed it necessary to assess the recoverability of long-lived asset groups for both contract drilling and pressure pumping. The Company performed a Step 1 analysis to assess the recoverability of long-lived assets within its contract drilling and pressure pumping segments. With respect to these assets, future cash flows were estimated over the expected remaining life of the assets, and the Company determined that, on an undiscounted basis, expected cash flows exceeded the carrying value of the long-lived assets, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the long-lived assets within the contract drilling and pressure pumping segments by approximately 120% and 60%, respectively.

Due to the continued deterioration of crude oil prices in the fourth quarter of 2015, management deemed it necessary to once again assess the recoverability of long-lived assets groups for both contract drilling and pressure pumping. The Company performed a Step 1 analysis to assess the recoverability of long-lived assets within its contract drilling and pressure pumping segments. With respect to these assets, future cash flows were estimated over the expected remaining life of the assets, and the Company determined that, on an undiscounted basis, expected cash flows exceeded the carrying value of the long-lived assets, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the long-lived assets within the contract drilling and pressure pumping segments by approximately 120% and 100%, respectively.

For both of the assessments performed in 2015, the expected cash flows for the contract drilling segment included the backlog of commitments for contract drilling revenues under term contracts, which was approximately $801 million and $710 million at September 30, 2015 and December 31, 2015, respectively. Rigs not under term contracts would be subject to pricing in the spot market. Utilization and rates for rigs in the spot market and for the pressure pumping segment were estimated based upon the Company's historical experience in prior downturns. Also, the expected cash flows for the contract drilling and pressure pumping segments were based on the assumption that activity levels in both segments would begin to recover in the first quarter of 2017 in response to improved oil prices.

5. Goodwill and Intangible Assets

Goodwill — Goodwill by operating segment as of December 31, 2017 and 2016 and changes for the years then ended are as follows (in thousands):

	Contract Drilling	Pressure Pumping	Directional Drilling	Oilfield Rental	Total
Balance December 31, 2015 and 2016	$86,234	$—	$ —	$—	$86,234
Goodwill acquired	308,826	121,444	88,685	6,284	525,239
Balance December 31, 2017	$395,060	$121,444	$ 88,685	$6,284	$611,473

There were no accumulated impairment losses related to goodwill as of December 31, 2017 or 2016.

Goodwill is evaluated at least annually as of December 31, or when circumstances require, to determine if the fair value of recorded goodwill has decreased below its carrying value. For purposes of impairment testing, goodwill is evaluated at the reporting unit level. The Company's reporting units for impairment testing have been determined to be its operating segments. The Company determines whether it is more likely than not that the fair value of a reporting unit is less than its carrying value after considering qualitative, market and other factors, and if this is the case, any necessary goodwill impairment is determined using a quantitative impairment test. From time to time, the Company may perform quantitative testing for goodwill impairment in lieu of performing the qualitative assessment. If this resulting fair value of goodwill is less than the carrying value of goodwill, an impairment loss would be recognized in the amount of such shortfall.

In January 2017, the FASB issued an accounting standards update to eliminate Step 2 from the goodwill impairment test. An entity will now perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value, but the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. The Company adopted this update in 2017. Prior to adoption the Company first determined whether it was more likely than not that the fair value of a reporting unit was less than its carrying value after considering qualitative, market and other factors, and if so, the resulting goodwill impairment was determined using a two-step quantitative impairment test. The first step of the quantitative testing was to compare the fair value of an entity's reporting units to the respective carrying value of those reporting units. If the carrying value of a reporting unit exceeded its fair value, the second step of the quantitative testing was performed whereby the fair value of the reporting unit was allocated to its identifiable tangible and intangible assets and liabilities, with any remaining fair value representing the fair value of goodwill. If this resulting fair value of goodwill was less than the carrying value of goodwill, an impairment loss was recognized in the amount of such shortfall.

In connection with its annual goodwill impairment assessment as of December 31, 2017 and 2016, the Company determined based on an assessment of qualitative factors that it was more likely than not that the fair values of its reporting units were greater than the respective carrying amount. In making this determination, the Company considered the current and expected levels of commodity prices for oil and natural gas, which influence the overall level of business activity in its reporting units, as well as the Company's operating results for 2017 and 2016 and forecasted operating results for the respective succeeding year. Management also considered the Company's overall market capitalization at December 31, 2017 and 2016.

During the third quarter of 2015, oil prices declined and averaged $46.42 per barrel, reaching a new low for 2015 of $38.22 per barrel in August 2015. In light of these lower oil prices in August, the Company lowered its expectations with respect to future activity levels in both the contract drilling and pressure pumping businesses. As a result of the Company's revised expectations of the duration of the lower oil and natural gas commodity price environment and the related deterioration of the markets for its contract drilling and pressure pumping services, the Company performed a quantitative Step 1 impairment assessment of its goodwill as of September 30, 2015. In completing the Step 1 assessment, the fair value of each reporting unit was estimated using both the income and market valuation methods. The estimate of fair value for each reporting unit required the use of significant unobservable inputs, representative of a Level 3 fair value measurement. The inputs included assumptions related to the future performance of the Company's contract drilling and pressure pumping reporting units, such as future oil and natural gas prices and projected demand for the Company's services, and assumptions related to discount rates, long-term growth rates and control premiums.

Based on the results of the Step 1 goodwill impairment test as of September 30, 2015, the fair value of the contract drilling reporting unit exceeded its carrying value by approximately 15%, and management concluded that no impairment was indicated in its contract drilling reporting unit; however, impairment was indicated in its pressure pumping reporting unit. In the third quarter of 2015, the Company recognized an impairment charge of $125 million associated with the impairment of all of the goodwill in its pressure pumping reporting unit.

In connection with its annual impairment asset at December 31, 2015, the Company performed a quantitative Step 1 impairment assessment of the goodwill in its contract drilling reporting unit. In completing the Step 1 assessment, the fair value of the contract drilling reporting unit was estimated using both the income and market valuation methods. The estimate of the fair value of the reporting unit required the use of significant unobservable inputs, representative of a Level 3 fair value measurement. The inputs included assumptions related to the future performance of the Company's contract drilling reporting unit, such as future oil and natural gas prices and projected demand for the Company's services, and assumptions related to discount rates, long-term growth rates and control premiums. Based on the results of the quantitative Step 1 impairment assessment of its goodwill as of December 31, 2015, the fair value of the contract drilling reporting unit exceeded its carrying value by approximately 16%, and management concluded that no impairment was indicated in its contract drilling reporting unit.

Intangible Assets — In 2017, intangible assets were recorded in the Company's directional drilling operating segment with the acquisition of MS Directional and in the contract drilling operating segment with the SSE merger (See Note 2). In addition, intangible assets were recorded in the pressure pumping operating segment in connection with the 2010 acquisition of the assets of a pressure pumping business. The Company's intangible assets were recorded at fair value on the date of acquisition and are amortized on a straight line basis. The following table identifies the segment and weighted average useful life of each of the Company's intangible assets:

	Segment	Weighted Average Useful Life (in years)
Customer relationships	Pressure pumping	7.00
Customer relationships	Directional drilling	3.00
Developed technology	Directional drilling	10.00
Favorable drilling contracts	Contract drilling	0.83
Internal use software	Directional drilling	5.00

The Company concluded that no triggering events necessitating an impairment assessment of the intangible assets had occurred in 2017, 2016 or 2015. The assessment of the recoverability of the respective operating segments asset group included the respective intangible assets, and no impairment was indicated.

The gross carrying amount and accumulated amortization of intangible assets as of December 31, 2017 and 2016 are as follows (in thousands):

	2017			2016		
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Customer relationships	$26,200	$ (1,943)	$ 24,257	$25,500	$ (22,768)	$ 2,732
Developed technology	48,000	(1,137)	46,863	—	—	—
Favorable drilling contracts	22,500	(18,482)	4,018	—	—	—
Internal use software	482	(21)	461	—	—	—
	$97,182	$ (21,583)	$ 75,599	$25,500	$ (22,768)	$ 2,732

Amortization expense on intangible assets of approximately $24.3 million, $3.6 million and $3.6 million for the years ended December 31, 2017, 2016 and 2015, respectively. The remaining amortization expense associated with finite-lived intangible assets is expected to be as follows (in thousands):

Year ending December 31,	
2018	$17,580
2019	13,630
2020	11,686
2021	4,896
2022	4,875
Thereafter	22,932
Total	$75,599

6. Accrued Expenses

Accrued expenses consisted of the following at December 31, 2017 and 2016 (in thousands):

	2017	2016
Salaries, wages, payroll taxes and benefits	$50,443	$21,138
Workers' compensation liability	80,751	67,775
Property, sales, use and other taxes	29,332	6,766
Insurance, other than workers' compensation	10,816	9,566
Accrued interest payable	7,558	6,740
Accrued merger and integration	16,101	—
Other	31,628	27,163
	$226,629	$139,148

7. Long-Term Debt

2012 Credit Agreement — On September 27, 2012, the Company entered into a Credit Agreement ("Base Credit Agreement") with Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender, and each of the other lenders party thereto. The Base Credit Agreement (as amended, the "Credit Agreement") is a committed senior unsecured credit facility that includes a revolving credit facility.

On July 8, 2016, the Company entered into Amendment No. 2 to the Credit Agreement (Amendment No. 2"), which amended the Base Credit Agreement to, among other things, make borrowings under the revolving credit facility subject to a borrowing base calculated by reference to the Company's and certain of its subsidiaries' eligible equipment, inventory, accounts receivable and unencumbered cash as described in Amendment No. 2. The revolving credit facility contains a letter of credit facility that is limited to $50 million and a swing line facility that is limited to $20 million, in each case outstanding at any time. The maturity date under the Base Credit Agreement was September 27, 2017 for the revolving credit facility; however, Amendment No. 2 extended the maturity date of $357.9 million in revolving credit commitments of certain lenders to March 27, 2019. On January 17, 2017, the Company entered into Amendment No. 3 to Credit Agreement, which amended the Credit Agreement by restating the definition of Consolidated EBITDA to provide for the add-back of transaction expenses related to the SSE merger. On January 24, 2017, the Company entered into an agreement with certain lenders under its revolving credit facility to increase the aggregate commitments under its revolving credit facility to approximately $595.8 million, subject to the satisfaction of certain conditions. The aggregate commitment increase became effective on April 20, 2017 upon the consummation of the SSE merger and the repayment and termination of the SSE credit facility. On April 20, 2017, the Company entered into Amendment No. 4 to Credit Agreement which permitted outstanding letters of credit under the SSE credit facility to be deemed to be incurred under the Company's credit facility and increased the amount of the accordion feature of the Company's revolving credit facility to permit aggregate commitments to be increased to an amount not to exceed $700 million (subject to satisfaction of certain conditions and the procurement of additional commitments from new or existing lenders). On April 20, 2017, the Company also entered into an additional commitment increase agreement with certain of its lenders pursuant to which total commitments available under the Company's revolving credit facility (after giving effect to both commitment increases) increased to $632 million through September 2017 and to $490 million through March 2019. On October 27, 2017, the Company entered into an additional commitment increase agreement with certain of its lenders pursuant to which total commitments available under the Company's revolving credit facility increased to $500 million through March 27, 2019.

Loans under the Credit Agreement bear interest by reference, at the Company's election, to the LIBOR rate or base rate, provided, that swing line loans bear interest by reference only to the base rate. Until September 27, 2017, the applicable margin on LIBOR rate loans varied from 2.75% to 3.25% and the applicable margin on base rate loans varied from 1.75% to 2.25%, in each case determined based upon the Company's debt to capitalization ratio. Beginning September 27, 2017, the applicable margin on LIBOR rate loans varies from 3.25% to 3.75% and the applicable margin on base rate loans varies from 2.25% to 2.75%, in each case determined based on the Company's excess availability under the credit facility. At December 31, 2017, the applicable margin on LIBOR rate loans was 3.50% and the applicable margin on base rate loans was 2.50%. A letter of credit fee is payable by the Company equal to the applicable margin for LIBOR rate loans times the amount available to be drawn under outstanding letters of credit. The commitment fee rate payable to the lenders for the unused portion of the credit facility is 0.50%.

Each domestic subsidiary of the Company unconditionally guarantees all existing and future indebtedness and liabilities of the other guarantors and the Company arising under the Credit Agreement, other than (a) Ambar Lone Star Fluid Services LLC, (b) domestic subsidiaries that directly or indirectly have no material assets other than equity interests in, or capitalization indebtedness owed by, foreign subsidiaries, and (c) any subsidiary having total assets of less than $1 million. Such guarantees also cover obligations of the Company and any subsidiary of the Company arising under any interest rate swap contract with any person while such person is a lender or an affiliate of a lender under the Credit Agreement.

The Credit Agreement requires compliance with two financial covenants. The Company must not permit its debt to capitalization ratio to exceed 40%. The Credit Agreement generally defines the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. The Company also must not permit its interest coverage ratio as of the last day of a fiscal quarter to be less than 3.00 to 1.00. The Credit Agreement generally defines the interest coverage ratio as the ratio of earnings before interest, taxes, depreciation and amortization ("EBITDA") of the four prior fiscal quarters to interest charges for the same period. The Company was in compliance with these covenants at December 31, 2017.

The Credit Agreement limits the Company's ability to make investments in foreign subsidiaries or joint ventures such that, if the book value of all such investments since September 27, 2012 is above 20% of the total consolidated book value of the assets of the Company and its subsidiaries on a pro forma basis, the Company will not be able to make such investment. The Credit Agreement also restricts the Company's ability to pay dividends and make equity repurchases, subject to certain exceptions, including an exception allowing such restricted payments if before and immediately after giving effect to such restricted payment, the Pro Forma Debt Service Coverage Ratio (as defined in the Credit Agreement) is at least 1.50 to 1.00. In addition, the Credit Agreement requires that, if the consolidated cash balance of the Company and its subsidiaries, subject to certain exclusions, is more than $100 million at the end of the day on which a borrowing is made, the Company can only use the proceeds from such borrowing to fund acquisitions, capital expenditures and the repurchase of indebtedness, and if such proceeds are not used in such manner within three business days, the Company must repay such unused proceeds on the fourth business day following such borrowings.

The Credit Agreement also contains customary representations, warranties and affirmative and negative covenants.

Events of default under the Credit Agreement include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, as well as a cross default event, loan document enforceability event, change of control event and bankruptcy and other insolvency events. If an event of default occurs and is continuing, then a majority of the lenders have the right, among others, to (i) terminate the commitments under the Credit Agreement, (ii) accelerate and require the Company to repay all the outstanding amounts owed under any loan document (provided that in limited circumstances with respect to insolvency and bankruptcy of the Company, such acceleration is automatic), and (iii) require the Company to cash collateralize any outstanding letters of credit.

As of December 31, 2017, the Company had $268 million outstanding under the revolving credit facility at a weighted average interest rate of 5.71%. The Company had $4.6 million in letters of credit outstanding under its revolving credit facility at December 31, 2017 and, as a result, had available borrowing capacity of $227 million at that date.

2015 Reimbursement Agreement — On March 16, 2015, the Company entered into a Reimbursement Agreement (the “Reimbursement Agreement”) with The Bank of Nova Scotia (“Scotiabank”), pursuant to which the Company may from time to time request that Scotiabank issue an unspecified amount of letters of credit. As of December 31, 2017, the Company had $54.9 million in letters of credit outstanding under the Reimbursement Agreement.

Under the terms of the Reimbursement Agreement, the Company will reimburse Scotiabank on demand for any amounts that Scotiabank has disbursed under any letters of credit. Fees, charges and other reasonable expenses for the issuance of letters of credit are payable by the Company at the time of issuance at such rates and amounts as are in accordance with Scotiabank’s prevailing practice. The Company is obligated to pay to Scotiabank interest on all amounts not paid by the Company on the date of demand or when otherwise due at the LIBOR rate plus 2.25% per annum, calculated daily and payable monthly, in arrears, on the basis of a calendar year for the actual number of days elapsed, with interest on overdue interest at the same rate as on the reimbursement amounts.

The Company has also agreed that if obligations under the Credit Agreement are secured by liens on any of its or any of its subsidiaries' property, then the Company's reimbursement obligations and (to the extent similar obligations would be secured under the Credit Agreement) other obligations under the Reimbursement Agreement and any letters of credit will be equally and ratably secured by all property subject to such liens securing the Credit Agreement.

Pursuant to a Continuing Guaranty dated as of March 16, 2015, the Company's payment obligations under the Reimbursement Agreement are jointly and severally guaranteed as to payment and not as to collection by subsidiaries of the Company that from time to time guarantee payment under the Credit Agreement.

Series A & B Senior Notes – On October 5, 2010, the Company completed the issuance and sale of $300 million in aggregate principal amount of its 4.97% Series A Senior Notes due October 5, 2020 (the "Series A Notes") in a private placement. The Series A Notes bear interest at a rate of 4.97% per annum. The Company pays interest on the Series A Notes on April 5 and October 5 of each year. The Series A Notes will mature on October 5, 2020.

On June 14, 2012, the Company completed the issuance and sale of $300 million in aggregate principal amounts of its 4.27% Series B Senior Notes due June 14, 2022 (the "Series B Notes") in a private placement. The Series B Notes bear interest at a rate of 4.27% per annum. The Company pays interest on the Series B Notes on April 5 and October 5 of each year. The Series B Notes will mature on June 14, 2022.

The Series A Notes and Series B Notes are senior unsecured obligations of the Company, which rank equally in right of payment with all other unsubordinated indebtedness of the Company. The Series A Notes and Series B Notes are guaranteed on a senior unsecured basis by each of the existing domestic subsidiaries of the Company other than subsidiaries that are not required to be guarantors under the Credit Agreement.

The Series A Notes and Series B Notes are prepayable at the Company's option, in whole or in part, provided that in the case of a partial prepayment, prepayment must be in an amount not less than 5% of the aggregate principal amount of the notes then outstanding, at any time and from time to time at 100% of the principal amount prepaid, plus accrued and unpaid interest to the prepayment date, plus a "make-whole" premium as specified in the note purchase agreements. The Company must offer to prepay the notes upon the occurrence of any change of control. In addition, the Company must offer to prepay the notes upon the occurrence of certain asset dispositions if the proceeds therefrom are not timely reinvested in productive assets. If any offer to prepay is accepted, the purchase price of each prepaid note is 100% of the principal amount thereof, plus accrued and unpaid interest thereon to the prepayment date.

The respective note purchase agreements require compliance with two financial covenants. The Company must not permit its debt to capitalization ratio to exceed 50% at any time. The note purchase agreements generally define the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. The Company also must not permit its interest coverage ratio as of the last day of a fiscal quarter to be less than 2.50 to 1.00. The note purchase agreements generally define the interest coverage ratio as the ratio of EBITDA for the four prior fiscal quarters to interest charges for the same period. The Company was in compliance with these covenants at December 31, 2017.

Events of default under the note purchase agreements include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, a cross default event, a judgment in excess of a threshold event, the guaranty agreement ceasing to be enforceable, the occurrence of certain ERISA events, a change of control event and bankruptcy and other insolvency events. If an event of default under the note purchase agreements occurs and is continuing, then holders of a majority in principal amount of the respective notes have the right to declare all the notes then-outstanding to be immediately due and payable. In addition, if the Company defaults in payments on any note, then until such defaults are cured, the holder thereof may declare all the notes held by it pursuant to the note purchase agreement to be immediately due and payable.

2028 Senior Notes – On January 19, 2018, the Company completed its offering of $525 million aggregate principal amount of the Company's 2028 Notes initially guaranteed on a senior unsecured basis by certain of its subsidiaries. The net proceeds before offering expenses were approximately $521 million of which the Company used $239 million to repay amounts outstanding under its revolving credit facility. The Company intends to use the remainder of the net proceeds for general corporate purposes.

The Company pays interest on the 2028 Notes on February 1 and August 1 of each year. The 2028 Notes will mature on February 1, 2028. The 2028 Notes bear interest at a rate of 3.95% per annum.

The 2028 Notes are senior unsecured obligations of the Company, which rank equally with all of the Company's other existing and future senior unsecured debt and will rank senior in right of payment to all of the Company's other future subordinated debt. The 2028 Notes will be effectively subordinated to any of the Company's future secured debt to the extent of the value of the assets securing such debt. In addition, the 2028 Notes will be structurally subordinated to the liabilities (including trade payables) of the Company's subsidiaries that do not guarantee the 2028 Notes. The guarantors' guarantees of the 2028 Notes (the "Guarantees") will rank equally in right of payment with all of the guarantors' future unsecured senior debt and senior in right of payment to all of the guarantors' future subordinated debt. The Guarantees will be effectively subordinated to any of the guarantors' future secured debt to the extent of the value of the assets securing such debt. In the future, the Guarantees may be released and terminated under certain circumstances.

The Company, at its option, may redeem the Notes in whole or part, at any time or from time to time at a redemption price equal to 100% of the principal amount of such 2028 Notes to be redeemed, plus accrued and unpaid interest, if any, on those 2028 Notes to the redemption date, plus a make-whole premium. Additionally, commencing on November 1, 2027, the Company, at its option, may redeem the 2028 Notes in whole or part, at a redemption price equal to 100% of the principal amount of the 2028 Notes to be redeemed, plus accrued and unpaid interest, if any, on those 2028 Notes to the redemption date.

The indenture pursuant to which the 2028 Notes were issued includes covenants that, among other things, limit the Company and its subsidiaries' ability to incur certain liens, engage in sale and lease-back transactions or consolidate, merge, or transfer all or substantially all of their assets. These covenants are subject to important qualifications and limitations set forth in the indenture.

Upon the occurrence of a change of control, as defined in the indenture, each holder of the 2028 Notes may require the Company to purchase all or a portion of such holder's 2028 Notes at a price equal to 101% of their principal amount, plus accrued and unpaid interest, if any, to, but excluding, the repurchase date.

The indenture also provides for events of default which, if any of them occurs, would permit or require the principal of, premium, if any, and accrued interest, if any, on the 2028 Notes to become or to be declared due and payable.

The Company incurred approximately $6.0 million in debt issuance costs in connection with the Credit Agreement. The Company incurred approximately $1.9 million in debt issuance costs in connection with the Series A Notes and approximately $1.6 million in debt issuance costs in connection with the Series B Notes. These costs were deferred and are being recognized as interest expense over the term of the underlying debt. Debt issuance costs, except those related to line-of-credit arrangements, are presented in the balance sheet as a direct deduction from the carrying amount of the related debt. Debt issuance costs related to line-of-credit arrangements are classified as a deferred charge. Amortization of debt issuance costs is reported as interest expense. Interest expense related to the amortization of debt issuance costs was approximately $2.6 million, $4.1 million and $2.8 million for the years ended December 31, 2017, 2016 and 2015, respectively. Amortization of debt issuance costs for the year ended December 31, 2016 includes $1.4 million of costs related to the early termination of the previous term loan agreements.

Presented below is a schedule of the principal repayment requirements of long-term debt by fiscal year as of December 31, 2017 (in thousands):

Year ending December 31,	
2018	$—
2019	268,000
2020	300,000
2021	—

2022	300,000
Thereafter	—
Total	$868,000

8. Commitments, Contingencies and Other Matters

Commitments – As of December 31, 2017, the Company maintained letters of credit in the aggregate amount of $59.5 million for the benefit of various insurance companies as collateral for retrospective premiums and retained losses which could become payable under the terms of the underlying insurance contracts. These letters of credit expire annually at various times during the year and are typically renewed. As of December 31, 2017, no amounts had been drawn under the letters of credit.

As of December 31, 2017, the Company had commitments to purchase approximately $172 million of major equipment for its drilling and pressure pumping businesses.

The Company's pressure pumping business has entered into agreements to purchase minimum quantities of proppants and chemicals from certain vendors. As of December 31, 2017, the remaining obligation under these agreements was approximately $140 million, of which materials with a total purchase price of approximately $35.9 million are required to be purchased during 2018. In the event that the required minimum quantities are not purchased during any contract year, the Company could be required to make a liquidated damages payment to the respective vendor for any shortfall.

Contingencies – The Company's operations are subject to many hazards inherent in the contract drilling and pressure pumping businesses, including inclement weather, blowouts, well fires, loss of well control, pollution, exposure and reservoir damage. These hazards could cause personal injury or death, work stoppage, and serious damage to equipment and other property, as well as significant environmental and reservoir damages. These risks could expose the Company to substantial liability for personal injury, wrongful death, property damage, loss of oil and natural gas production, pollution and other environmental damages.

Any contractual right to indemnification that the Company may have for any such risk may be unenforceable or limited due to negligent or willful acts of commission or omission by the Company, its subcontractors and/or suppliers. In addition, certain states, including Louisiana, New Mexico, Texas and Wyoming, have enacted statutes generally referred to as "oilfield anti-indemnity acts" expressly prohibiting certain indemnity agreements contained in or related to oilfield service agreements. Such oilfield anti-indemnity acts may restrict or void a party's indemnification of the Company. The Company's customers and other third parties may dispute, or be unable to meet, their contractual indemnification obligations to the Company due to financial, legal or other reasons. Accordingly, the Company may be unable to transfer these risks to its customers and other third parties by contract or indemnification agreements. Incurring a liability for which the Company is not fully indemnified or insured could have a material adverse effect on its business, financial condition, cash flows and results of operations.

The Company has insurance coverage for fire, windstorm and other risks of physical loss to its rigs and certain other assets, employer's liability, automobile liability, commercial general liability, workers' compensation and insurance for other specific risks. The Company has also elected in some cases to accept a greater amount of risk through increased deductibles on certain insurance policies. For example, the Company generally maintains a $1.5 million per occurrence deductible on its workers' compensation insurance coverage, a $1.0 million per occurrence deductible on its equipment insurance coverage, a $2.0 million per occurrence deductible on its general liability coverage and a $2.0 million per occurrence deductible on its automobile liability insurance coverage. The Company also self-insures a number of other risks, including loss of earnings and business interruption and cyber risks, and does not carry a significant amount of insurance to cover risks of underground reservoir damage.

On January 22, 2018, an accident at a drilling site in Pittsburg County, Oklahoma resulted in the losses of life of five people, including three of the Company's employees. Based on the information the Company has available as of the date of this Report, the Company believes that it has adequate insurance to cover any losses, excluding the applicable insurance deductibles and investigation-related expenses. However, if this accident is not, or another significant accident or other event occurs that is not, fully covered by insurance or an enforceable and recoverable indemnity from a third party, it could have a material adverse effect on the Company's business, financial condition, cash flows and results of operations.

The Company is party to various legal proceedings arising in the normal course of its business. The Company does not believe that the outcome of these proceedings, either individually or in the aggregate, will have a material adverse effect on its financial condition, results of operations or cash flows.

Other Matters — The Company has Change in Control Agreements with its Chairman of the Board and one of its Executive Vice Presidents (the "Specified Employees"). Each Change in Control Agreement generally has an initial term with automatic twelve-month renewals unless the Company notifies the Specified Employee at least ninety days before the end of such renewal period that the term will not be extended. If a change in control of the Company occurs during the term of the agreement and the Specified Employee's employment is terminated (i) by the Company other than for cause or other than automatically as a result of death, disability or retirement, or (ii) by the Specified Employee for good reason (as those terms are defined in the Change in Control Agreements), then the Specified Employee shall generally be entitled to, among other things:

- a bonus payment equal to the highest bonus paid after the Change in Control Agreement was entered into (such bonus payment for each Specified Employee prorated for the portion of the fiscal year preceding the termination date);
- a payment equal to 2.5 times (in the case of the Chairman of the Board) or 2 times (in the case of the Executive Vice President) of the sum of (i) the highest annual salary in effect for such Specified Employee and (ii) the average of the three annual bonuses earned by the Specified Employee for the three fiscal years preceding the termination date and
- continued coverage under the Company's welfare plans for up to three years (in the case of the Chairman of the Board) or two years (in the case of the Executive Vice President).

Each Change in Control Agreement provides the Specified Employee with a full gross-up payment for any excise taxes imposed on payments and benefits received under the Change in Control Agreements or otherwise, including other taxes that may be imposed as a result of the gross-up payment.

The Company has Employment Agreements with its Chief Executive Officer, Chief Financial Officer, General Counsel and the President of the Company's subsidiary, Patterson-UTI Drilling Company LLC ("Patterson-UTI Drilling"). In the case of the Chief Executive Officer and the General Counsel, the Employment Agreement supersedes the prior Change in Control Agreement with each executive and, in the case of the President of Patterson-UTI Drilling, the Employment Agreement supersedes his prior employment agreement. Each Employment Agreement generally has an initial three-year term, subject to automatic annual renewal. The executive may terminate his employment under his Employment Agreement by providing written notice of such termination at least 30 days before the effective date of such termination. Under specified circumstances, the Company may terminate the executive's employment under his Employment Agreement for Cause (as defined in the Employment Agreement) by either (i) providing written notice 10 days before the effective date of such termination and by granting at least 10 days to cure the cause for such termination or (ii) by providing written notice of such termination at least 30 days before the effective date of such termination and by granting at least 20 days to cure the cause for such termination, provided that if the matter is reasonably determined by the Company to not be capable of being cured, the executive may be terminated for cause on the date the written notice is delivered. The Employment Agreement also provides for, among other things, severance payments and the continuation of certain benefits following termination by the Company of the executive other than for Cause, or termination by the executive for Good Reason (as defined in each Employment Agreement). Under these provisions, if the executive's employment is terminated by the Company without Cause, or the executive terminates his employment for Good Reason:

- the executive will have the right to receive a lump-sum payment consisting of 3 times (in the case of the Chief Executive Officer) or 2.5 times (in the case of the Chief Financial Officer, General Counsel and President of Patterson-UTI Drilling) the sum of (i) his base salary and (ii) the average annual cash bonus received by him for the three years prior to the date of termination;
- the executive will have the right to receive a pro-rated lump-sum payment equal to his annual cash bonus based on actual results for the year, payable at the same time as annual cash bonuses are paid to active employees,
- the Company will accelerate vesting of all options and restricted stock awards on the 60th day following the executive's termination, and
- the Company will pay the executive certain accrued obligations and certain obligations pursuant to the terms of employee benefit plans.

If a termination by the Company other than for Cause or by the executive for Good Reason occurs following a Change in Control (as defined in his Employment Agreement, which for the President of Patterson-UTI Drilling includes a change in control of the Company or, in certain circumstances, of Patterson-UTI Drilling), the executive will generally be entitled to the same severance payments and benefits described above except that the pro-rated lump-sum payment for annual cash bonuses will be based on his highest annual cash bonus for the last three years, and the executive will be entitled to 36 months (in the case of the Chief Executive Officer) or 30 months (in the case of the Chief Financial Officer, General Counsel and President of Patterson-UTI Drilling) of subsidized benefits continuation coverage.

9. Stockholders' Equity

Stock Offering – On January 27, 2017, the Company completed an offering of 18.2 million shares of its common stock and raised net proceeds of $472 million. The Company used the net proceeds of the offering to repay SSE's outstanding indebtedness of approximately $472 million.

Cash Dividends – The Company paid cash dividends during the years ended December 31, 2017, 2016 and 2015 as follows:

	Per Share	Total (in thousands)
2017		
Paid on March 22, 2017	$0.02	$ 3,326
Paid on June 22, 2017	0.02	4,269
Paid on September 21, 2017	0.02	4,271
Paid on December 21, 2017	0.02	4,449
Total cash dividends	$0.08	$ 16,315
2016		
Paid on March 24, 2016	$0.10	$ 14,712
Paid on June 23, 2016	0.02	2,953
Paid on September 22, 2016	0.02	2,953
Paid on December 22, 2016	0.02	2,961
Total cash dividends	$0.16	$ 23,579
2015		
Paid on March 25, 2015	$0.10	$ 14,640
Paid on June 24, 2015	0.10	14,712
Paid on September 24, 2015	0.10	14,712
Paid on December 24, 2015	0.10	14,711
Total cash dividends	$0.40	$ 58,775

On February 7, 2018, the Company's Board of Directors approved a cash dividend on its common stock in the amount of $0.02 per share to be paid on March 22, 2018 to holders of record as of March 8, 2018. The amount and timing of all future dividend payments, if any, are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial condition, terms of the Company's debt agreements and other factors.

On September 6, 2013, the Company's Board of Directors approved a stock buyback program that authorizes purchase of up to $200 million of the Company's common stock in open market or privately negotiated transactions. All purchases to date have been through open market transactions. Purchases under the program are made at management's discretion, at prevailing prices, subject to market conditions and other factors. Purchases may be made at any time without prior notice. Shares of stock purchased under the plan are held as treasury shares. There is no expiration date associated with the buyback program. As of December 31, 2017, the Company had remaining authorization to purchase approximately $187 million of the Company's outstanding common stock under the 2013 stock buyback program.

The Company acquired shares of stock from directors during 2017 and 2016 and from employees during 2017, 2016 and 2015 that are accounted for as treasury stock. Certain of these shares were acquired to satisfy the exercise price in connection with the exercise of stock options. The remainder of these shares was acquired to satisfy payroll withholding obligations upon the settlement of performance unit awards and the vesting of restricted stock. These shares were acquired at fair market value. These acquisitions were made pursuant to the terms of the Patterson-UTI

Energy, Inc. 2014 Long-Term Incentive Plan (the "2014 Plan") and not pursuant to the stock buyback program.

Treasury stock acquisitions during the years ended December 31, 2017, 2016 and 2015 were as follows (dollars in thousands):

	2017		2016		2015	
	Shares	Cost	Shares	Cost	Shares	Cost
Treasury shares at beginning of period	43,392,617	$911,094	43,207,240	$907,045	42,818,585	$899,035
Purchases pursuant to 2013 stock buyback program	5,503	109	8,488	183	8,618	180
Acquisitions pursuant to long-term incentive plan	404,491	7,508	176,889	3,866	380,037	7,830
Treasury shares at end of period	43,802,611	$918,711	43,392,617	$911,094	43,207,240	$907,045

10. Stock-based Compensation

The Company uses share-based payments to compensate employees and non-employee directors. The Company recognizes the cost of share-based payments under the fair-value-based method. Share-based awards consist of equity instruments in the form of stock options, restricted stock or restricted stock units and have included service and, in certain cases, performance conditions. The Company issues shares of common stock when vested stock options are exercised, when restricted stock is granted and when restricted stock units and share-settled performance unit awards vest.

The 2014 Plan was originally approved by the Company’s stockholders effective as of April 17, 2014, and the Board of Directors adopted a resolution that no future grants would be made under any of the Company’s other previously existing plans. On June 29, 2017, the Company’s stockholders approved the amendment and restatement of the 2014 Plan (the “Amended and Restated Plan”) to increase the number of shares available under the plan to 10,049,156 shares. The aggregate number of shares of the Company’s common stock authorized for grant under the Amended and Restated Plan is 18.9 million, which includes 9.1 million shares previously authorized under the 2014 Plan. The Company’s share-based compensation plans at December 31, 2017 are as follows:

Plan Name	Shares Authorized for Grant	Shares Underlying Awards Outstanding	Shares Available for Grant
Amended and Restated Plan	18,900,000	5,286,459	7,647,874
Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, as amended	—	3,804,500	—

A summary of the Amended and Restated Plan follows:

- The Compensation Committee of the Board of Directors administers the plan other than the awards to directors.
- All employees, officers and directors are eligible for awards.
- The Compensation Committee determines the vesting schedule for awards. Awards typically vest over one year for non-employee directors and three years for employees.
- The Compensation Committee sets the term of awards and no option term can exceed 10 years.
- All options granted under the plan are granted with an exercise price equal to or greater than the fair market value of the Company’s common stock at the time the option is granted.
- The plan provides for awards of incentive stock options, non-incentive stock options, tandem and freestanding stock appreciation rights, restricted stock awards, other stock unit awards, performance share awards, performance unit awards and dividend equivalents. As of December 31, 2017, non-incentive stock options, restricted stock awards, restricted stock units and performance unit awards had been granted under the plan.

Options granted under the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (the “2005 Plan”) typically vested over one year for non-employee directors and three years for employees. All options were granted with an exercise price equal to the fair market value of the related common stock at the time of grant. Restricted stock awards granted under the 2005 Plan typically vested over one year for non-employee directors and three years for employees.

Stock Options—The Company estimates the grant date fair values of stock options using the Black-Scholes-Merton valuation model. Volatility assumptions are based on the historic volatility of the Company’s common stock over the most recent period equal to the expected term of the options as of the date the options are granted. The expected term assumptions are based on the Company’s experience with respect to employee stock option activity. Dividend yield assumptions are based on the expected dividends at the time the options are granted. The risk-free interest rate assumptions are determined by reference to United States Treasury yields. No options were granted during the year ended December 31, 2017. Weighted-average assumptions used to estimate grant date fair values for stock options granted during the years ended December 31, 2016 and 2015 are as follows:

	2016	2015
Volatility	35.11%	37.95%
Expected term (in years)	5.00	5.00

Dividend yield	2.05 %	2.00 %
Risk-free interest rate	1.40 %	1.37 %

Stock option activity for the year ended December 31, 2017 follows:

	Shares	Weighted-average exercise price
Outstanding at beginning of year	6,687,150	$ 20.68
Exercised	(50,000)	$ 18.63
Expired	(600,000)	$ 24.17
Outstanding at end of year	6,037,150	$ 20.35
Exercisable at end of year	5,515,968	$ 20.49

Options outstanding at December 31, 2017 have an aggregate intrinsic value of approximately $25.9 million and a weighted-average remaining contractual term of 4.65 years. Options exercisable at December 31, 2017 have an aggregate intrinsic value of approximately $23.7 million and a weighted-average remaining contractual term of 4.31 years. Additional information with respect to options granted, vested and exercised during the years ended December 31, 2017, 2016 and 2015 follows:

	2017	2016	2015
Weighted-average grant date fair value of stock options granted (per share)	NA	$4.90	$5.79
Aggregate grant date fair value of stock options vested during the year (in thousands)	$4,565	$4,729	$5,077
Aggregate intrinsic value of stock options exercised (in thousands)	$209	$366	$—

As of December 31, 2017, options to purchase 521,182 shares were outstanding and not vested. All of these non-vested options are expected to ultimately vest. Additional information as of December 31, 2017 with respect to these non-vested options follows:

Aggregate intrinsic value	$2.1 million
Weighted-average remaining contractual term	8.2 years
Weighted-average remaining expected term	3.2 years
Weighted-average remaining vesting period	1.4 years
Unrecognized compensation cost	$2.6 million

Restricted Stock—For all restricted stock awards to date, shares of common stock were issued when the awards were made. Non-vested shares are subject to forfeiture for failure to fulfill service conditions and, in certain cases, performance conditions. Non-forfeitable dividends are paid on non-vested shares of restricted stock. The Company uses the straight-line method to recognize periodic compensation cost over the vesting period.

Restricted stock activity for the year ended December 31, 2017 follows:

	Shares	Weighted-average Grant Date Fair Value
Non-vested restricted stock outstanding at beginning of year	1,427,455	$ 22.26
Granted	890,904	$ 21.78
Vested	(764,213)	$ 23.40
Forfeited	(23,808)	$ 22.34
Non-vested restricted stock outstanding at end of year	1,530,338	$ 21.41

As of December 31, 2017, approximately 1.5 million shares of non-vested restricted stock outstanding are expected to vest. Additional information as of December 31, 2017 with respect to these non-vested shares follows:

Aggregate intrinsic value	$34.0 million
Weighted-average remaining vesting period	1.3 years
Unrecognized compensation cost	$19.6 million

Restricted Stock Units—For all restricted stock unit awards made to date, shares of common stock are not issued until the units vest. Restricted stock units are subject to forfeiture for failure to fulfill service conditions and, in certain cases, performance conditions. Non-forfeitable cash dividend equivalents are paid on certain non-vested restricted stock units, and forfeitable dividend equivalents are accrued on certain other restricted stock units that will be paid upon vesting. The Company uses the straight-line method to recognize periodic compensation cost over the vesting period.

Restricted stock unit activity for the year ended December 31, 2017 follows:

	Shares	Weighted-average Grant Date Fair Value
Non-vested restricted stock units outstanding at beginning of year	191,655	$ 19.85
Granted	1,238,692	$ 19.85
Assumed (1)	505,551	$ 22.45
Vested	(549,451)	$ 22.24
Forfeited	(49,174)	$ 21.26
Non-vested restricted stock units outstanding at end of year	1,337,273	$ 19.80

(1) Restricted stock unit awards under the Seventy Seven Energy Inc. 2016 Omnibus Incentive Plan, which was adopted, assumed, amended and renamed by the Company in connection with the SSE merger. No additional awards will be made under this plan.

Performance Unit Awards. The Company has granted share-settled performance unit awards to certain executive officers (the "Performance Units") on an annual basis since 2010. The Performance Units provide for the recipients to receive a grant of shares of common stock upon the achievement of certain performance goals during a specified period established by the Compensation Committee. The performance period for the Performance Units is the three year period commencing on April 1 of the year of grant, except that for the Performance Units granted in 2013 the performance period was extended pursuant to its terms, as described below, and for the Performance Units granted in 2017 the three-year performance period commenced on May 1.

The performance goals for the Performance Units are tied to the Company's total shareholder return for the performance period as compared to total shareholder return for a peer group determined by the Compensation Committee. These goals are considered to be market conditions under the relevant accounting standards and the market conditions were factored into the determination of the fair value of the respective Performance Units. Generally, the recipients will receive a target number of shares if the Company's total shareholder return during the performance period, when compared to the peer group, is at the 50th percentile. If the Company's total shareholder return during the performance period, when compared to the peer group, is at the 75th percentile or higher, then the recipients will receive two times the target number of shares. If the Company's total shareholder return during the performance period, when compared to the peer group, is at the 25th percentile, the recipients will only receive one-half of the target number of shares. If the Company's total shareholder return during the performance period, when compared to the peer group, is between the 25th and 75th percentile, then the shares to be received by the recipients will be determined on a pro-rata basis.

For the Performance Units awarded prior to 2016, there is no payout unless the Company's total shareholder return is positive and, when compared to the peer group, is at or above the 25th percentile. In respect of the 2013 Performance Units, for which the performance period ended March 31, 2016, the Company's total shareholder return for the performance period was negative, the Company's total shareholder return for the performance period when compared to the peer group was above the 75th percentile, and there was no payout; provided, however, that pursuant to the terms of those 2013 awards, if, during the two-year period ending March 31, 2018, the Company's total shareholder return for any 30 consecutive day period equals or exceeds 18 percent on an annualized basis from April 1, 2013 through the last day of such 30 consecutive day period, and the recipient is actively employed by the Company through the last day of the extended performance period, then the Company will issue to the recipient the number of shares equal to the amount the recipient would have been entitled to receive had the Company's total shareholder return been positive during the initial three-year performance period.

For the Performance Units granted in April 2016, if the Company's total shareholder return is negative, and, when compared to the peer group is at or above the 25th percentile, then the recipients will receive one-half of the number of shares they would have received had the Company's total shareholder return been positive. For the Performance Units granted in May 2017, the payout is based on relative performance and does not have an absolute performance requirement.

The total target number of shares with respect to the Performance Units for the years 2012-2017 is set forth below:

	2017 Performance Unit Awards	2016 Performance Unit Awards	2015 Performance Unit Awards	2014 Performance Unit Awards	2013 Performance Unit Awards	2012 Performance Unit Awards
Target number of shares	186,198	185,000	190,600	154,000	236,500	192,000

The 2012 Performance Units settled with an 87th total shareholder return percentile and 384,000 shares were issued. The 2014 Performance Units settled with an 89th total shareholder return percentile and a negative total shareholder return, so there was no payout under such Performance Units.

Because the Performance Units are stock-settled awards, they are accounted for as equity awards and measured at fair value on the date of grant using a Monte Carlo simulation model. The fair value of the Performance Units is set forth below (in thousands):

	2017 Performance Unit Awards	2016 Performance Unit Awards	2015 Performance Unit Awards	2014 Performance Unit Awards	2013 Performance Unit Awards	2012 Performance Unit Awards
Aggregate fair value at date of grant	$ 5,780	$ 3,854	$ 4,052	$ 5,388	$ 5,564	$ 3,065

These fair value amounts are charged to expense on a straight-line basis over the performance period. Compensation expense associated with the Performance Units is set forth below (in thousands):

	2017 Performance Unit Awards	2016 Performance Unit Awards	2015 Performance Unit Awards	2014 Performance Unit Awards	2013 Performance Unit Awards	2012 Performance Unit Awards
Year ended December 31, 2017	$ 1,284	$ 1,285	$ 1,351	$ 449	NA	NA
Year ended December 31, 2016	NA	$ 963	$ 1,351	$ 1,796	$ 464	NA
Year ended December 31, 2015	NA	NA	1,013	$ 1,796	$ 1,855	$ 255

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Dividends on Equity Awards – Non-forfeitable cash dividends are paid on restricted stock awards and dividend equivalents are paid or accrued on certain restricted stock units. These dividends are recognized as follows:

- Dividends are recognized as reductions of retained earnings for the portion of restricted stock awards expected to vest.
- Dividends are recognized as additional compensation cost for the portion of restricted stock awards that are not expected to vest or that ultimately do not vest.
- Dividend equivalents are recognized as reductions of retained earnings for the portion of restricted stock units expected to vest.
- Dividend equivalents are recognized as additional compensation cost for the portion of restricted stock units that are not expected to vest or that ultimately do not vest.

11. Leases

The Company incurred rent expense of $48.9 million, $25.3 million and $37.6 million for the years ended December 31, 2017, 2016 and 2015, respectively. Rent expense is primarily related to short-term equipment rentals that are generally passed through to customers.

Future minimum rental payments required under operating leases having initial or remaining non-cancelable lease terms in excess of one year at December 31, 2017 are as follows (in thousands):

Year ending December 31,	
2018	$13,616
2019	9,368
2020	7,112
2021	5,165
2022	3,844
Thereafter	8,917
Total	$48,022

12. Income Taxes

Components of the income tax provision applicable to federal, state and foreign income taxes for the years ended December 31, 2017, 2016 and 2015 are as follows (in thousands):

	2017	2016	2015
Federal income tax benefit:			
Current	$(42)	$(24,777)	$(42,020)
Deferred	(335,106)	(134,592)	(83,812)
	(335,148)	(159,369)	(125,832)
State income tax expense (benefit):			

Current	(215)	(257)	(3,480)
Deferred	4,511	(14,163)	(12,433)
	4,296	(14,420)	(15,913)
Foreign income tax expense (benefit):			
Current	(3,108)	(368)	(2,590)
Deferred	249	(3,405)	(3,628)
	(2,859)	(3,773)	(6,218)
Total income tax benefit:			
Current	(3,365)	(25,402)	(48,090)
Deferred	(330,346)	(152,160)	(99,873)
Total income tax benefit:	$(333,711)	$(177,562)	$(147,963)

The difference between the statutory federal income tax rate and the effective income tax rate for the years ended December 31, 2017, 2016 and 2015 is summarized as follows:

	2017	2016	2015
Statutory tax rate	35.0 %	35.0%	35.0%
State income taxes - net of the federal income tax benefit	1.9	2.0	2.1
Permanent differences	(1.3)	(0.1)	(1.3)
One-time tax effects of tax reform	66.7	—	—
Share-based payments	3.6	—	—
Acquisition related differences	(3.3)	—	—
Other differences, net	(0.8)	(1.1)	(2.4)
Effective tax rate	101.8%	35.8%	33.4%

The effective tax rate increased by approximately 66.0% to 101.8% for 2017 compared to 2016, primarily due to a 66.7% increase related to tax reform enacted on December 22, 2017 and a 3.6% increase for excess tax benefits from employee stock compensation deductions. These increases were partially offset by a 3.3% decrease in the effective tax rate for acquisitions that resulted in the revaluation of deferred tax assets and liabilities at the new state tax rates at which they are expected to reverse. The lower 2015 effective tax rate is primarily related to the impact of goodwill impairment charges in 2015, along with an adjustment to the Company's deferred tax liability associated with the 2010 conversion of its Canadian operations to a controlled foreign corporation.

Tax reform reduces the U.S. federal corporate tax rate from 35% to 21% beginning in 2018, requires companies to pay a one-time transition tax on foreign earnings that were previously tax deferred, creates new taxes on future foreign earnings, places a new limitation on the tax deductibility of interest expense, accelerates the expensing of certain business assets, and reduces the amount of executive pay that will be tax deductible, among other changes. Based on a reduced U.S. federal corporate tax rate of 21% from tax reform, the Company remeasured certain deferred tax assets and liabilities at the tax rates at which they are expected to reverse in the future. Due to the limited time to consider tax reform and its various interpretations, the Company is still analyzing and refining its calculations, which could potentially affect the measurement of these balances or give rise to new deferred tax amounts, however, in certain cases, the Company has made a reasonable estimate of the effects on its existing deferred tax balances and the one-time transition tax. For the items for which the Company was able to determine a reasonable estimate, it recognized a provisional amount, in accordance with SAB 118, of approximately $219 million of tax benefit, which is included as a component of income tax expense from continuing operations resulting in the above impact to the Company's 2017 effective income tax rate.

The one-time transition tax is based on the total post-1986 earnings and profits (E&P) of the Company's foreign operation which it has previously deferred from U.S. income taxes. Based on its current analysis, the Company has estimated an E&P deficit and therefore has not recorded any additional taxes for the one-time transition tax. The Company notes that its analysis of the transition tax is provisional and represents a reasonable estimate resulting from the mandatory deemed repatriation of its post-1986 untaxed foreign E&P. Determining the provisional transition tax required a significant number of steps, including determining the composition of the Company's post-1986 untaxed foreign E&P that is held in cash or liquid assets and other assets at several measurement dates, as a different rate is applied to each when determining the transition tax liability, and analyzing the Company's accumulated foreign post-1986 E&P, including historical practices and assertions. As a result of these factors, as well as the proximity of the enactment of tax reform to its year-end, the Company had limited time to consider tax reform and its various interpretations and has not completed its calculation of the total post-1986 E&P amounts of its foreign operations. Adjustments to the Company's estimates may occur once it finalizes these calculations.

Prior to tax reform, the Company had elected to permanently reinvest unremitted earnings in Canada effective January 1, 2010, and it intended to do so for the foreseeable future. As a result, no deferred United States federal or state income taxes had been provided on such unremitted foreign earnings. With the enactment of tax reform, there is a new territorial tax system that provides for a 100% dividends received deduction on future earnings, if remitted. However, the Company will need to continue to evaluate its reinvestment intentions on future earnings and any other residual basis differences in order to determine whether it can continue to assert indefinite reinvestment or whether it will be required to provide for additional taxes that would be due on future earnings if remitted, such as foreign withholding taxes or state and local taxes. The Company will also need to determine whether it will be required to provide for additional taxes on any other outside basis differences in its foreign operations. Due to the limited time to consider these provisions, the Company is still evaluating how tax reform will affect its existing accounting position to indefinitely reinvest unremitted foreign earnings. The Company will continue to assert permanent reinvestment with respect to future unremitted earnings and has not recorded any deferred federal or state income taxes that would be provided on future unremitted earnings. The Company will finalize its intentions on whether it will permanently reinvest its foreign unremitted earnings within the measurement period provided under SAB 118.

Tax reform also introduced a new GILTI U.S. tax on certain off-shore earnings at an effective tax rate of 10.5% for tax years beginning after December 31, 2017 (increasing to 13.125% for tax years beginning after December 31, 2025) with a partial offset for any related foreign tax credits. The Company is still evaluating the GILTI provisions of tax reform and its impact, if any, on the Company's consolidated financial statements at December 31, 2017. The FASB staff allowed companies to adopt an accounting policy to either provide deferred taxes for GILTI or treat it as a tax cost in the year incurred. The Company has not yet determined its accounting policy because determining the impact of the GILTI provisions requires analysis of its existing legal entity structure, the reversal of differences in the assets and liabilities of its foreign subsidiaries, and its ability to offset any tax with foreign tax credits. As such, the Company did not record a deferred income tax expense or benefit related to the GILTI provisions in its consolidated statement of operations for the year ended December 31, 2017 and will finalize its evaluation of the GILTI provisions during the measurement period provided under SAB 118.

In addition to the provisions above, the tax reform also changed the individuals whose compensation is subject to a $1 million cap on deductibility under Section 162(m) and includes performance-based compensation such as stock options and stock appreciation rights in the calculation. For taxable years beginning before December 31, 2017, a public company had been able to deduct up to $1 million of compensation paid to covered employees consisting of the chief executive officer and the next three highest compensated officers, but not the chief financial officer (CFO). However, the limit did not apply to performance-based compensation. The new law expands the definition of covered employees to include the CFO and any individual who has been considered a covered employee, even if that individual is no longer a covered employee. Thus, once an individual is a covered employee, the deduction limitation applies to compensation paid to that individual at any point in the future, including after a separation from service. Any individual who is a covered employee for a tax year after December 31, 2016 will remain a covered employee for all future years. The law also eliminates the exception for performance-based compensation. The provision generally applies to taxable years beginning after December 31, 2017 and provides a transition for compensation paid pursuant to a written binding contract that is in effect on November 2, 2017. The Company will need to carefully review the terms of its compensation plans and agreements to assess whether such plans and agreements are considered to be written binding contracts in effect on November 2, 2017. Due to the complexity of applying this new provision and the limited time to consider tax reform, the Company has not yet completed its analysis of these new provisions and will finalize its analysis during the measurement period provided under SAB 118.

In March 2016, the FASB issued Accounting Standards Update No. 2016-09, "Compensation-Stock Compensation". The new standard was effective for the Company on January 1, 2017. Among other provisions, the new standard requires that excess tax benefits and tax deficiencies that arise upon vesting or exercise of share-based payments be recognized as income tax benefits and expenses in the income statement. Previously, such amounts were recorded to additional paid-in-capital. This aspect of the new guidance was required to be adopted prospectively. The effective income tax rate for the year ended December 31, 2017 includes approximately $12 million of excess tax benefits from share-based compensation awards that vested or were exercised during the period.

During 2017, there was significant merger and acquisition activity by the Company. Based on this activity, an evaluation was made of the Company's overall state deferred tax rate, resulting in a slightly increased rate. The Company remeasured certain deferred tax assets and liabilities at the tax rates at which they are expected to reverse in the future and recorded additional taxes of approximately $11 million, impacting the 2017 effective income tax rate.

The tax effect of significant temporary differences representing deferred tax assets and liabilities at December 31, 2017 and 2016 are as follows (in thousands):

	2017	2016
Deferred tax assets:		
Net operating loss carryforwards	$285,542	$203,485
Alternative minimum tax credit	7,907	7,907
Scientific research and experimental development tax credit	898	—
Expense associated with stock options and restricted stock	12,338	17,116
Workers' compensation allowance	19,662	26,157
Federal benefit of state deferred tax liabilities	5,660	5,310
Other	27,066	14,998
Total deferred tax assets	359,073	274,973
Deferred tax liabilities:		
Property and equipment basis difference	(695,111)	(911,972)
Other	(10,923)	(9,538)
Total deferred tax liabilities	(706,034)	(921,510)
Net deferred tax liability	$(346,961)	$(646,537)

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized, and necessary allowances are provided. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the Company's carryback availability, the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. The Company expects the full carrying value of its deferred tax assets at December 31, 2017 and 2016 to be realized as a result of the timing of the reversals of its existing taxable temporary differences, which will give rise to taxable income and offset deductible temporary differences in the permitted carryforward periods. As of December 31, 2017, the Company does not consider a valuation allowance necessary.

Other deferred tax assets consist primarily of the tax effect of various allowance accounts and tax-deferred expenses expected to generate future tax benefits of approximately $27.1 million. Other deferred tax liabilities of approximately $10.9 million consists primarily of the tax effect of receivables from insurance companies and tax-deferred income not yet recognized for tax purposes.

For income tax purposes, the Company has approximately $1.1 billion of gross federal net operating losses, approximately $19.2 million of Canadian net operating losses and approximately $678 million of post-apportionment state net operating losses as of December 31, 2017. Of these amounts, approximately $11 million of Canadian and $1 million of state losses will be carried back to prior years and the remaining balance can be carried forward to future years. Net operating losses that can be carried forward, if unused, are scheduled to expire as follows: 2023—$137,000; 2024—$2.4 million; 2025—$2.8 million; 2026—$17.4 million; 2027—$102,000; 2029—$33.2 million; 2030—$28.6 million; 2031—$101.9 million; 2032—$9.7 million; 2034—$30,000; 2035—$302.7 million, 2036 - $644.6 million; and 2037—$647.1 million.

As of December 31, 2017, the Company had no unrecognized tax benefits. The Company has established a policy to account for interest and penalties related to uncertain income tax positions as operating expenses. As of December 31, 2017, the tax years ended December 31, 2013 through December 31, 2016 are open for examination by U.S. taxing authorities. As of December 31, 2017, the tax years ended December 31, 2013 through December 31, 2016 are open for examination by Canadian taxing authorities.

13. Employee Benefits

The Company maintains a 401(k) plan for all eligible employees. The Company's operating results include expenses of approximately $8.7 million in 2017, $4.4 million in 2016 and $7.1 million in 2015 for the Company's contributions to the plan.

14. Business Segments

At December 31, 2017, the Company had three business segments: (i) contract drilling of oil and natural gas wells, (ii) pressure pumping services and (iii) directional drilling services. Each of these segments represents a distinct type of business. These segments have separate management teams which report to the Company's chief operating decision maker. The results of operations in these segments are regularly reviewed by the chief operating decision maker for purposes of determining resource allocation and assessing performance.

Contract Drilling — The Company markets its contract drilling services to major and independent oil and natural gas operators. As of December 31, 2017, the Company had 295 marketed land-based drilling rigs in the continental United States and western Canada.

For the years ended December 31, 2017, 2016 and, 2015, contract drilling revenue earned in Canada was $13.7 million, $15.6 million and $37.5 million, respectively. Additionally, long-lived assets within the contract drilling segment located in Canada totaled $52.0 million and $44.0 million as of December 31, 2017 and 2016, respectively.

Pressure Pumping — The Company provides pressure pumping services to oil and natural gas operators primarily in Texas and the Mid-Continent and Appalachian regions. Pressure pumping services are primarily well stimulation services (such as hydraulic fracturing) and cementing services for the completion of new wells and remedial work on existing wells. Well stimulation involves processes inside a well designed to enhance the flow of oil, natural gas, or other desired substances from the well. Cementing is the process of inserting material between the wall of the well bore and the casing to support and stabilize the casing.

Directional Drilling — The Company provides a comprehensive suite of directional drilling services in most major producing onshore oil and gas basins in the United States.

Major Customer — During 2017, no single customer accounted for more than 10% of the Company’s consolidated operating revenues. During 2016, one customer accounted for approximately $124 million or 14% of the Company’s consolidated operating revenues. During 2015, one customer accounted for approximately $244 million or 13% of the Company’s consolidated operating revenues. These revenues in 2015 and 2016 were earned in both the Company’s contract drilling and pressure pumping businesses.

The following tables summarize selected financial information relating to the Company's business segments (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Revenues:			
Contract drilling	$1,041,492	$544,196	$1,155,565
Pressure pumping	1,200,311	354,070	712,454
Directional drilling	45,580	—	—
Other operations(a)	76,781	18,299	24,931
Elimination of intercompany revenues(b)	(7,480)	(699)	(1,673)
Total revenues	$2,356,684	$915,866	$1,891,277
Income (loss) before income taxes:			
Contract drilling	$(171,897)	$(235,858)	$(78,970)
Pressure pumping	21,028	(176,628)	(254,998)
Directional drilling	(21)	—	—
Other operations	(20,813)	(3,391)	(14,269)
Corporate	(152,792)	(54,672)	(57,088)
Other operating income (expense), net (c)	31,957	14,323	(1,647)
Interest income	1,866	327	964
Interest expense	(37,472)	(40,366)	(36,475)
Other	343	69	34
Loss before income taxes	$(327,801)	$(496,196)	$(442,449)
Identifiable assets:			
Contract drilling	$3,931,994	$3,032,819	$3,457,044
Pressure pumping	1,209,424	653,630	813,704
Directional drilling	301,275	—	—
Other operations	172,094	48,885	38,726
Corporate(d)	144,069	36,957	155,574
Total assets	$5,758,856	$3,772,291	$4,465,048
Depreciation, depletion, amortization and impairment:			
Contract drilling	$538,891	$467,974	$618,434
Pressure pumping	198,006	184,872	214,552
Directional drilling	9,347	—	—
Other operations	29,402	10,114	26,301
Corporate	7,695	5,474	5,472
Total depreciation, depletion, amortization and impairment	$783,341	$668,434	$864,759
Capital expenditures:			
Contract drilling	$354,425	$72,508	$527,054
Pressure pumping	171,436	39,584	197,577
Directional drilling	7,795	—	—
Other operations	31,547	6,116	16,625
Corporate	1,884	1,591	2,520
Total capital expenditures	$567,087	$119,799	$743,776

(a) Other operations includes the Company's oilfield rental tools business, pipe handling components and related technology business, the oil and natural gas working interests and the Middle East/North Africa activities.

(b) In 2017, intercompany revenues consists of contract drilling and revenues from other operations for services provided to contract drilling, pressure pumping and within other operations. In 2016, intercompany revenues consists of contract drilling and revenues within other operations. In 2015, intercompany revenues only consisted of contract drilling.

(c) Other operating income (expense), net includes net gains or losses associated with the disposal of assets relate to corporate strategy decisions of the executive management group. Accordingly, the related gains or losses have been separately presented and excluded from the results of specific segments. This caption also includes expenses related to certain legal settlements net of insurance reimbursements.

(d) Corporate assets primarily include cash on hand, income tax receivables, certain property and equipment, and certain deferred tax assets.

15. Concentrations of Credit Risk

Financial instruments which potentially subject the Company to concentrations of credit risk consist primarily of demand deposits, temporary cash investments and trade receivables.

The Company believes it has placed its demand deposits and temporary cash investments with high credit-quality financial institutions. At December 31, 2017 and 2016, the Company's demand deposits and temporary cash investments consisted of the following (in thousands):

	2017	2016
Deposits in FDIC and SIPC-insured institutions under insurance limits	$13,860	$846
Deposits in FDIC and SIPC-insured institutions over insurance limits	106,849	12,866
Deposits in foreign banks	21,479	27,557
	142,188	41,269
Less outstanding checks and other reconciling items	(99,360)	(6,117)
Cash and cash equivalents	$42,828	$35,152

Concentrations of credit risk with respect to trade receivables are primarily focused on companies involved in the exploration and development of oil and natural gas properties. The concentration is somewhat mitigated by the diversification of customers for which the Company provides services. As is general industry practice, the Company typically does not require customers to provide collateral. No significant losses from individual customers were experienced during the years ended December 31, 2017, 2016 or 2015. No expense for bad debts was recognized in 2017, 2016 or 2015.

16. Fair Values of Financial Instruments

The carrying values of cash and cash equivalents, trade receivables and accounts payable approximate fair value due to the short-term maturity of these items. These fair value estimates are considered Level 1 fair value estimates in the fair value hierarchy of fair value accounting.

The estimated fair value of the Company's outstanding debt balances as of December 31, 2017 and 2016 is set forth below (in thousands):

	December 31, 2017		December 31, 2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Borrowings under Credit Agreement:				
Revolving credit facility	$268,000	$268,000	$—	$—
4.97% Series A Senior Notes	300,000	303,966	300,000	283,534
4.27% Series B Senior Notes	300,000	295,616	300,000	263,194
Total debt	$868,000	$867,582	$600,000	$546,728

The carrying value of the balances outstanding under the revolving credit facility approximates its fair values as this instrument has floating interest rates. The fair values of the Series A Notes and Series B Notes at December 31, 2017 and 2016 are based on discounted cash flows associated with the respective notes using current market rates of interest at those respective dates. For the Series A Notes, the current market rates used in measuring this fair value were 4.46% at December 31, 2017 and 6.65% at December 31, 2016. For the Series B Notes, the current market rates used in measuring this fair value were 4.64% at December 31, 2017 and 7.02% at December 31, 2016. These fair value estimates are based on observable market inputs and are considered Level 2 fair value estimates in the fair value hierarchy of fair value accounting.

17. Quarterly Financial Information (in thousands, except per share amounts) (unaudited)

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2017				
Operating revenues	$305,175	$579,186	$684,989	$787,334
Operating loss	(92,639)	(140,236)	(38,016)	(21,647)
Net income (loss)	(63,539)	(92,184)	(33,769)	195,402
Net income (loss) per common share:				
Basic	$(0.40)	$(0.46)	$(0.16)	$0.88
Diluted	$(0.40)	$(0.46)	$(0.16)	$0.88
2016				
Operating revenues	$268,939	$193,907	$206,133	$246,887
Operating loss	(95,259)	(124,332)	(123,409)	(113,226)
Net loss	(70,503)	(85,866)	(84,143)	(78,122)
Net loss per common share:				
Basic	$(0.48)	$(0.58)	$(0.58)	$(0.53)
Diluted	$(0.48)	$(0.58)	$(0.58)	$(0.53)

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

Description	Beginning Balance	Charged to Costs and Expenses	Deductions(1)	Ending Balance
	(In thousands)			
Year Ended December 31, 2017				
Deducted from asset accounts:				
Allowance for doubtful accounts	$3,191	$ —	$ (868)	$2,323
Year Ended December 31, 2016				
Deducted from asset accounts:				
Allowance for doubtful accounts	$3,545	$ —	$ (354)	$3,191
Year Ended December 31, 2015				
Deducted from asset accounts:				
Allowance for doubtful accounts	$3,546	$ —	$ (1)	$3,545

(1) Consists of uncollectible accounts written off.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Patterson-UTI Energy, Inc. has duly caused this Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

PATTERSON-UTI ENERGY, INC.

By: /s/ William Andrew Hendricks, Jr.
William Andrew Hendricks, Jr.
President and Chief Executive Officer

Date: February 20, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report on Form 10-K has been signed by the following persons on behalf of Patterson-UTI Energy, Inc. and in the capacities indicated as of February 20, 2018.

Signature	Title
/s/ Mark S. Siegel Mark S. Siegel	Chairman of the Board
/s/ William Andrew Hendricks, Jr. William Andrew Hendricks, Jr. (Principal Executive Officer)	President, Chief Executive Officer and Director
/s/ C. Andrew Smith C. Andrew Smith (Principal Financial and Accounting Officer)	Executive Vice President and Chief Financial Officer
/s/ Charles O. Buckner Charles O. Buckner	Director
/s/ Michael W. Conlon Michael W. Conlon	Director
/s/ Curtis W. Huff Curtis W. Huff	Director
/s/ Terry H. Hunt Terry H. Hunt	Director
/s/ Tiffany J. Thom Tiffany J. Thom	Director

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