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, 2019

or

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

For the transition period from __________ to __________

Commission File Number 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	Trading Symbol	Name of Exchange on Which Registered
Common Stock, $0.01 Par Value	PTEN	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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ or No ☐

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the 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 28, 2019, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $2.3 billion, calculated by reference to the closing price of $11.51 for the common stock on the Nasdaq Global Select Market on that date.

As of February 7, 2020, the registrant had outstanding 192,151,761 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 2020 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, press releases and presentations 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. As used in this Report, "the Company," "us," "we," our" and like terms refer collectively to Patterson-UTI Energy, Inc. and its consolidated subsidiaries. Patterson-UTI Energy, Inc. conducts its operations through its wholly-owned subsidiaries and has no employees or independent business operations. 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," "predict," "potential," "project," "pursue," "should," "strategy," "target," or "will," or the negative thereof and other words and expressions of 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.

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:

- adverse oil and natural gas industry conditions;
- global economic conditions;
- 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;
- excess availability of land drilling rigs, pressure pumping and directional drilling equipment, including as a result of reactivation, improvement or construction;
- competition and demand for our services;
- strength and financial resources of competitors;
- utilization, margins and planned capital expenditures;
- liabilities from operational risks for which we do not have and receive full indemnification or insurance;
- 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);
- the ability to realize backlog;
- specialization of methods, equipment and services and new technologies, including the ability to develop and obtain satisfactory returns from new technology;
- shortages, delays in delivery, and interruptions in supply, of equipment and materials;
- cybersecurity events;
- the ability to retain management and field personnel;

- loss of key customers;
- synergies, costs and financial and operating impacts of acquisitions;
- difficulty in building and deploying new equipment;
- governmental regulation;
- environmental, social and governance practices, including the perception thereof;
- environmental risks and ability to satisfy future environmental costs;
- legal proceedings and actions by governmental or other regulatory agencies;
- technology-related disputes;
- the ability to effectively identify and enter new markets;
- weather;
- operating costs;
- expansion and development trends of the oil and natural gas industry;
- ability to obtain insurance coverage on commercially reasonable terms;
- financial flexibility;
- interest rate volatility;
- adverse credit and equity market conditions;
- availability of capital and the ability to repay indebtedness when due;
- stock price volatility;
- compliance with covenants under our debt agreements; and
- other financial, operational and legal risks and uncertainties detailed from time to time in our filings with the SEC.

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. 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 one of the largest fleets of land-based drilling rigs in the United States 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, from time to time, we pursue contract drilling opportunities outside of North America. As of December 31, 2019, we had a drilling fleet that consisted of 216 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. Substantially all of the revenue in the pressure pumping segment is from well stimulation services (such as hydraulic fracturing) for 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. As of December 31, 2019, we had approximately 1.3 million fracturing horsepower to provide these services. We also provide wireline and cementing services through the pressure pumping segment. Our wireline services offering primarily consists of “plug-and-perf,” which involves the setting of plugs between hydraulic fracturing stages and the creation of perforations for each cluster within the fracturing stage itself. Cementing is the process of inserting material between the wall of the well bore and the casing to support and stabilize the casing. 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, measurement-while-drilling, wireline steering tools and services that improve the statistical accuracy of horizontal wellbore placement.

We have other operations through which we provide oilfield rental tools in select markets in the United States. We also service equipment for drilling contractors, and we provide electrical controls and automation to the energy, marine and mining industries 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

Recent Developments in Financing and Merger and Acquisition Activity — On November 15, 2019, we completed an offering of $350 million in aggregate principal amount of our 5.15% Senior Notes due November 15, 2029 (the “2029 Notes”). The net proceeds before offering expenses were approximately $347 million. On December 16, 2019, we used a portion of the net proceeds from the offering to prepay our

4.27% Series B Senior Notes due June 14, 2022. The total amount of the prepayment, including the applicable "make-whole" premium, was approximately $315 million, plus accrued interest to the prepayment date. The remaining net proceeds and available cash on hand was used to repay $50 million of the borrowings under the Term Loan Agreement (as defined below).

On August 22, 2019, we entered into a term loan agreement (the "Term Loan Agreement") that permits a single borrowing of up to $150 million, which we drew in full on September 23, 2019. Subject to customary conditions, we may request that the lenders' aggregate commitments be increased by up to $75 million, not to exceed total commitments of $225 million. On September 25, 2019, we used $150 million of borrowings from the Term Loan Agreement and approximately $158 million of cash on hand to prepay our 4.97% Series A Senior Notes due October 5, 2020. The total amount of the prepayment, including the applicable "make-whole" premium, was approximately $308 million, plus accrued interest to the prepayment date. We repaid $50 million of the borrowings under the Term Loan Agreement on December 16, 2019, and we had $100 million in outstanding borrowings under the Term Loan Agreement as of December 31, 2019.

On October 25, 2018, we acquired all of the issued and outstanding shares of Current Power Solutions, Inc. ("Current Power"). Current Power is a provider of electrical controls and automation to the energy, marine and mining industries.

On March 27, 2018, we entered into an amended and restated credit agreement, which is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to $600 million, including a letter of credit facility that, at any time outstanding, is limited to $150 million and a swing line facility that, at any time outstanding, is limited to $20 million.

On February 20, 2018, we acquired the business of Superior QC, LLC ("Superior QC"), including its assets and intellectual property. Superior QC is a provider of software and services used to improve the statistical accuracy of horizontal wellbore placement. Superior QC's measurement-while-drilling (MWD) Survey FDIR (fault detection, isolation and recovery) service is a data analytics technology to analyze MWD survey data in real-time and more accurately identify the position of a well.

On January 19, 2018, we completed an offering of $525 million in aggregate principal amount of our 3.95% Senior Notes due 2028. 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.

On October 11, 2017, we acquired all of the issued and outstanding limited liability company interests of MS Directional, LLC (f/k/a Multi-Shot, LLC) ("MS Directional"). 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, measurement-while-drilling, and wireline steering tools.

On April 20, 2017, pursuant to an Agreement and Plan of Merger with Seventy Seven Energy Inc. ("SSE"), a subsidiary of ours was merged with and into SSE (the "SSE merger"), with SSE continuing as the surviving entity and one of our wholly-owned subsidiaries. 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 fracturing equipment located in Oklahoma and Texas. The oilfield rentals business acquired through the SSE merger has a 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 Current Power since October 25, 2018, the results of operations of Superior QC since February 20, 2018, 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.

Recent Developments in Market Conditions — Quarterly average oil prices and our quarterly average number of rigs operating in the United States for 2017, 2018 and 2019 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
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
2018:				
Average oil price per Bbl (1)	$62.88	$68.04	$69.76	$59.08
Average rigs operating per day — U.S.(2)	166	175	177	182
2019:				
Average oil price per Bbl (1)	$54.83	$59.78	$56.37	$56.94
Average rigs operating per day — U.S.(2)	174	157	142	122

(1) The average oil price represents the average monthly West Texas Intermediate (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.

Oil prices have recovered from a 12-year low of $26.19 in February 2016 and reached a high of $77.41 in June 2018. Oil prices remain volatile, as the closing price of oil began the year at a low of $46.31 per barrel on January 2, 2019, before increasing by 43% over the course of four months to reach a high of $66.24 per barrel in late April 2019. Since May 2019, oil prices have generally ranged between $50 and $60 per barrel. Oil prices averaged $56.94 per barrel in the fourth quarter of 2019 and closed at $50.06 per barrel on February 3, 2020.

Our rig count declined significantly during the industry downturn that began in late 2014, improved following the second quarter of 2016, and has declined since the fourth quarter of 2018. Our average active rig count for the fourth quarter of 2019 was 123 rigs, which included 122 rigs in the United States and less than one rig operating in Canada. This was a decrease from our average active rig count for the third quarter of 2019 of 142 rigs, which included 142 rigs in the United States and less than one rig in Canada. Our rig count in the United States at December 31, 2019 of 121 rigs was less than the rig count of 183 rigs at December 31, 2018. Term contracts have supported our operating rig count during the last three years. Based on contracts currently in place, we expect an average of 77 rigs operating under term contracts during the first quarter of 2020 and an average of 58 rigs operating under term contracts throughout 2020.

The pressure pumping market showed signs of oversupply in the second half of 2018 and was oversupplied in 2019. In response to oversupplied market conditions, we reduced the number of active pressure pumping spreads to 11 as of the end of 2019. We expect to average ten active pressure pumping spreads during the first quarter of 2020.

Industry Segments

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

- contract drilling services,
- pressure pumping services, and
- directional drilling services.

Our contract drilling services industry segment had operating losses in 2019, 2018 and 2017. Our pressure pumping services industry segment had operating losses in 2019 and 2018 and operating income in 2017. Our directional drilling services industry segment was a new segment for us as a result of the MS Directional acquisition in 2017 and accounted for approximately 7.6% and 6.3% percent of our 2019 and 2018 consolidated revenues, respectively. Our directional drilling segment had operating losses in 2019, 2018 and 2017.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 16 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, 2019, we had 216 marketed land-based drilling rigs based in the following regions:

- 64 in west Texas and southeastern New Mexico,
- 18 in north central and east Texas and northern Louisiana,
- 35 in the Rocky Mountain region (Colorado, Wyoming and North Dakota),
- 25 in south Texas,
- 31 in western Oklahoma,
- 37 in the Appalachian region (Pennsylvania, Ohio and West Virginia), and
- 6 in western Canada.

Our marketed drilling rigs have rated maximum depth capabilities ranging from approximately 13,200 feet to 24,000 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 $943 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 2019, 2018 and 2017, we spent approximately $194 million, $395 million and $354 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 (we define term contracts as contracts with a duration of six months or more) or for a specified number of wells. During 2019, our average number of days to drill a well (which includes moving to the drill site, rigging up and rigging down) was approximately 20 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, pursuant to which 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.

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

	Year Ended December 31,		
	2019	2018	2017
Average rigs operating per day — U.S.(1)	149	175	136
Average rigs operating per day — Canada(1)	1	1	2
Number of rigs operated during the year	189	193	179
Number of wells drilled during the year	2,703	3,088	2,553
Number of operating days	54,544	64,479	50,427

(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 improved the capability of our drilling fleet during the last several years. 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, 2019, 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	172	—	172	94%
APEX® 1000 HP rigs	12	—	12	100%
APEX® 2000 HP rigs	6	—	6	67%
APEX® 1400 HP rigs	5	—	5	100%
APEX® 1200 HP rigs	3	—	3	100%
Other electric rigs	12	6	18	72%
Total	210	6	216	
Average horsepower	1,458	1,117	1,448	

The U.S. land rig industry refers 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 at least a 750,000-pound hookload, a 7,500-psi circulating system, and is pad-capable. We currently estimate there are approximately 690 super-spec rigs in the United States, which includes 150 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, Ohio, West Virginia 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), the Mid-Continent region (Mid-Con Region) and the Appalachian region (Northeast Region). Pressure pumping services consist primarily of well stimulation services (such as hydraulic fracturing) 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 and proppant under pressure into the well bore to fracture the formation. Many wells in conventional plays also receive well stimulation services. We also provide cementing services through the pressure pumping segment. 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 cementing and acid pumping services, with a total of approximately 1.4 million horsepower as of December 31, 2019. Pressure pumping equipment at December 31, 2019 included:

	Fracturing Equipment	Other Pumping Equipment	Total
West Texas Region			
Number of units	207	17	224
Approximate horsepower	492,000	18,555	510,555
South Texas Region			
Number of units	112	—	112
Approximate horsepower	270,750	—	270,750
Mid-Con Region			
Number of units	68	—	68
Approximate horsepower	157,000	—	157,000
Northeast Region			
Number of units	186	12	198
Approximate horsepower	416,900	8,000	424,900
Combined:			
Number of units	573	29	602
Approximate horsepower	1,336,650	26,555	1,363,205

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 may not cover all of our required supply. These supply arrangements 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.

Wireline — Our wireline services offering primarily consists of "plug-and-perf," which involves the setting of plugs between hydraulic fracturing stages and the creation of perforations for each cluster within the fracturing stage itself. These wireline services are complementary to our pressure pumping services. As of December 31, 2019, we had not yet performed any wireline operations.

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, measurement-while-drilling (MWD), and wireline steering tools, in most major onshore oil and natural gas basins in the United States. We generally design, assemble and maintain our own fleet of downhole drilling motors and MWD equipment. 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.

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.

Equipment — We generally design, assemble, maintain and inspect our own equipment. We have developed proprietary equipment for our drilling motors, mud pulse and electromagnetic data transfer MWD equipment. 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, 2019, we had a comprehensive fleet of over 1,000 motors. In addition to our motor fleet, we had over 100 MWD systems.

Horizontal Wellbore Placement — We provide software and services used to improve the statistical accuracy of horizontal wellbore placement. Our measurement-while-drilling (MWD) Survey FDIR (fault detection, isolation and recovery) service is a data analytics technology to analyze MWD survey data in real-time and more accurately identify the position of a well. We provide these services to customers with onshore and offshore operations.

Oilfield Rentals

Our oilfield rentals business has a 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 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.

Other Operations

We service equipment for drilling contractors, and we provide electrical controls and automation to the energy, marine and mining industries 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.

Contracts

We believe that our contract drilling, pressure pumping, directional drilling, oilfield rentals and other 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 or supplier, any of which rights and obligations may deviate from what is customary due to particular industry conditions, customer or supplier 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 2019, we received approximately 41% from our ten largest customers and approximately 26% from our five largest customers. During 2019, 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, 2019 and 2018 was approximately $605 million and $770 million, respectively. Approximately 28% of the total contract drilling backlog at December 31, 2019 is reasonably expected to remain after 2020. 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 our contract drilling, pressure pumping and directional drilling businesses has frequently exceeded demand, particularly in an industry downturn. The price for our services is a key competitive factor, in part because equipment used in these 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.

Sustainability

We strive to be a leader in our industry in the area of environmental, social, governance and other sustainability-related issues, and we remain committed to managing these issues for the long-term benefit of our employees, communities and our business. We aim to minimize our environmental impact in the communities in which we work and live, while providing services for our customers in a safe and responsible manner. We invest extensively in the safety, health and well-being of our people, who are our most important asset and our greatest strength. Importantly, we maintain a rigorous focus on ethics and integrity at every level of our operations, a practice on which all of our success depends.

We continue to pursue initiatives to make improvements in air quality, water quality, land usage, use of energy and reducing waste materials. For example:

- we utilize natural gas engines, dual-fuel equipment and other technologies that reduce our carbon and other greenhouse gas emissions; and

- we employ spill prevention plans and use additional protective measures in environmentally sensitive areas.

Our goal is to provide an incident-free work environment. The safety of our employees and others is our highest priority, and we have robust safety training programs in place that are designed to comply with applicable laws and industry standards and to benefit our employees, communities and our business. All field-based employees are required to attend an Employee Safety Orientation, which includes classes on behavior-based safety, hazard awareness, safe systems of work, permission to work, time out for safety, energy isolation, hazard communication (HAZCOM), material handling and other topics.

We are committed to fostering a work environment where all people feel valued and respected. We offer our workforce the opportunity to advance in their professional careers through intensive, multi-day classroom training programs in numerous skills and competencies as well as management training programs. These programs are geared to providing our employees with opportunities to advance throughout our company. We embrace our diversity of people, thoughts and talents, and combine these strengths to pursue extraordinary results for our company, our employees and our stockholders.

In 2019, we trained over 4,000 employees on our Code of Business Conduct and Ethics, which addresses conflicts of interest, confidentiality, fair dealing with others, proper use of company assets, compliance with laws, insider trading, keeping of books and records, zero tolerance for discrimination and harassment in the work environment, as well as reporting of violations.

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 and acidizing and related well servicing activities, including wireline services,
- directional drilling services,
- services that improve the statistical accuracy of horizontal wellbore placement, including for customers with offshore operations,
- containment and disposal of hazardous materials, oilfield waste, other waste materials and acids,
- use of underground storage tanks and injection wells,
- servicing of equipment for drilling contractors,
- provision of electrical controls and automation, 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 and products 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.

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 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. The EPA issued a report on April 23, 2019, determining that no revisions were necessary. However, if changes are made to the classification of exploration and production wastes under CERCLA and/or RCRA in the future, 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 and Related Divestment and Other Efforts 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, explosions, 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. An accident or other event resulting in significant environmental or property damage, or injuries or fatalities involving our employees or other persons could also trigger investigations by federal, state or local authorities. Such an accident or other event could cause us to incur substantial expenses in connection with the investigation, remediation and resolution, as well as cause lasting damage to our reputation, loss of customers and an inability to obtain insurance.

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 $10.0 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 most cybersecurity risks, and we do not carry a significant amount of insurance to cover risks of underground reservoir damage.

Our insurance may 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 5,800 full-time employees as of February 7, 2020. 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 calendar years, we have recently experienced slower activity 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 availability of capital for oil and natural gas industry participants, including our customers,
- the availability of and constraints in pipeline, storage and other transportation capacity in the basins in which we operate,
- the environmental, tax and other laws and governmental regulations regarding the exploration, development, production, use 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 revenues, profitability and cash flows are highly dependent upon prevailing prices for oil and natural gas and expectations about future prices. Oil and natural gas prices and markets can be 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"), its members and other oil-producing nations, such as Russia, 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,
- changes to tax, tariff and import/export regulations by the United States or other countries,
- 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. Oil prices reached a twelve-year low of $26.19 per barrel in February 2016. As a result of the lower level of oil prices, our industry experienced a severe decline in activity levels. While oil and natural gas prices modestly recovered since the first quarter of 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. Oil prices remain volatile, as the closing price of oil started the year at a low of $46.31 per barrel on January 2, 2019, before increasing by 43% over the course of four months to reach a high of $66.24 per barrel in late April 2019. Since May 2019, oil prices have generally ranged between $50 and $60 per barrel.

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, as well as our customers' ability to access sources of capital to fund their operating and capital expenditures. A decline in demand for oil and natural gas, prolonged low oil or natural gas prices, expectations of decreases in oil and natural gas prices or a reduction in the ability of our customers to access capital 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 historically moderate or 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.

Demand for energy and for oil and natural gas end products is highly sensitive to economic conditions; as a result, global economic conditions, indications that economic growth is slowing 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. An economic slowdown or recession in the United States or in any other country that significantly affects the supply of or demand for oil or natural gas could negatively impact our operations and therefore adversely affect our results. 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, or expectations for the global economic environment, will not quickly deteriorate again due to one or more factors. A deterioration in the global economic environment could have a material adverse effect on our business, financial condition, cash flows and results of operations.

A Surplus of 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 or capital spending reductions by our customers due to investor requirements or other reasons 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 new and upgraded drilling rigs and pressure pumping equipment. Low commodity prices and new and upgraded equipment 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 a surplus of equipment.

We periodically seek to increase the prices on our services to offset rising costs, earn returns on our capital investment, and otherwise generate higher returns for our stockholders. However, we operate in a very competitive industry, and we are not always successful in raising or maintaining our existing prices. With the active rig count below the peak seen in 2014 and many rigs, including highly capable AC rigs, and pressure pumping equipment still idle, there is considerable pricing pressure in the industry. Even if we are able to increase our prices, we may not be able to do so at a rate that is sufficient to offset rising costs without adversely affecting our activity levels. The inability to maintain our pricing and to increase our pricing as costs increase could have a material adverse effect on our business, financial condition, cash flows and results of operations. 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 a surplus of equipment can cause oil and natural gas service contractors to have difficulty maintaining pricing, utilization and profit margins and, at times, result in operating losses. We cannot predict the future level of competition or surplus equipment in the oil and natural gas service businesses or the level of demand for our contract drilling, pressure pumping or directional drilling services.

The surplus of operable land drilling rigs, increasing rig specialization and surplus of 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. For example, we recognized impairment charges of $221 million and $277 million in 2019 and 2018, respectively.

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, explosions, fires, loss of well control, equipment failure, 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. An accident or other event resulting in significant environmental or property damage, or injuries or fatalities involving our employees or other persons could also trigger investigations by federal, state or local authorities. Such an accident or other event could cause us to incur substantial expenses in connection with the investigation, remediation and resolution, as well as cause lasting damage to our reputation, loss of customers and an inability to obtain insurance.

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. 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 $10.0 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 most of our cybersecurity risks, and we do not carry a significant amount of insurance to cover risks of underground reservoir damage.

Our insurance may 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.

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, 2019, 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 $605 million. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a description of our calculation of backlog. Our contract drilling backlog may decline, as fixed-term drilling contract coverage over time may not be offset by new contracts or may be reduced by price adjustments to existing 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.

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 pressure pumping and other equipment. Our customers are increasingly demanding the services of newer, higher specification drilling rigs and pressure pumping and other equipment, as well as new and improved technology and data analytics. Accordingly, we may have to allocate a higher proportion of our capital expenditures to maintain and improve existing rigs and pressure pumping and other equipment, purchase and construct newer, higher specification drilling rigs and pressure pumping and other equipment to meet the increasingly sophisticated needs of our customers, and develop new and improved technology and data analytics. 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 and technology 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.

We continually attempt to develop new technologies for use in our business. In the event that we are successful in developing new technologies for use in our business, there is no guarantee of future demand for those technologies. Customers may be reluctant or unwilling to adopt our new technologies. We may also have difficulty negotiating satisfactory terms for our new technologies, including terms that would enable us to obtain acceptable returns on our investment in the research and development of new technologies.

Development of new technology is critical to maintaining our competitiveness. There can be no assurance that we will be able to successfully develop technology that our customers demand. 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 reduce our competitiveness and 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.

Periodically, the oilfield services 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 and in developing new technologies. 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 2019, we received approximately 41% from our ten largest customers, 26% from our five largest customers and 7% 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.

Our Business Is Subject to Cybersecurity Risks and Threats.

Our operations are increasingly dependent on effective and secure 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, attempts to gain unauthorized access to our data and systems, 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, including via “phishing” or similar attacks directed at us or our customers;
- 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;
- destruction or damage to our and our customers’ equipment;
- downtime and loss of revenue;
- injury to our reputation;

- negative impacts on our ability to compete;
- loss or damage to our information technology systems, including worksite data delivery systems;
- exposure to litigation; and
- increased costs to prevent, respond to or mitigate cybersecurity events.

Although we utilize various procedures and controls to mitigate our exposure to such risks, cybersecurity attacks and other cyber events are evolving and unpredictable. There can be no assurance that the procedures and controls that we implement, or that we cause third party service providers to implement, will be sufficient to protect our systems, information or other property. 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 of time. We self-insure most of our cybersecurity risks, and any such incident could have a material adverse effect on our business, financial condition, cash flows and results of operations. As cyber incidents continue to evolve, we may be required to incur additional costs to continue to modify or enhance our protective measures or to investigate or remediate the effects of cyber incidents.

Growth Through Acquisitions, the Building or Upgrading of Equipment and the Development of Technology Is Not Assured.

We have grown our drilling rig fleet and pressure pumping fleet and expanded our business lines and use of technology in the past through mergers, acquisitions, new construction and technology development. 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 or upgrading equipment or developing new technology. 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, our competitors may continue to build new equipment and develop new technology.

There can be no assurance that we will:

- have sufficient capital resources to complete additional acquisitions, build or upgrade equipment or develop new technology,
- successfully integrate additional equipment, acquired or developed technology or other assets or businesses,
- effectively manage the growth and increased size of our organization and, equipment,
- successfully deploy idle, stacked, upgraded or additional equipment and acquired or developed technology,
- maintain the crews necessary to operate additional equipment or the personnel necessary to evaluate, develop and deploy new technology, or
- successfully improve our financial condition, results of operations, business or prospects as a result of any completed acquisition, the building or upgrading equipment or the development of new technology.

Our failure to achieve consolidation savings, to integrate acquired businesses and technology and other 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, prior to our establishment of adequate compliance oversight or in connection with disputes over acquired or developed technology. While we generally seek to obtain indemnities for liabilities arising from 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 or upgrade equipment or develop new technology, and we also may issue equity, convertible or debt securities in connection with any such acquisitions or building or upgrade 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 or judgments,
- 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 places that 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 equipment and automation to the energy, marine and mining industries and a provider of directional drilling and other services, we may be deemed to be a responsible party under these laws and regulations.

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.

Numerous political and regulatory authorities, governmental bodies and officials, and environmental groups devote resources to campaigns aimed at eradicating 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. A number of presidential candidates have also stated that they would support either increased regulation or a ban on hydraulic fracturing; however, we cannot predict whether hydraulic fracturing regulations will be enacted or how stringent they may be. In addition, members of the U.S. Congress and the EPA have reviewed proposals for more stringent regulation of hydraulic fracturing, and various state and local initiatives have been or may be proposed or implemented to further regulate hydraulic fracturing. For example, the EPA conducted a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and 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. The EPA has not yet finalized this rule. 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, several jurisdictions have taken steps to enact hydraulic fracturing bans, moratoria or increased regulations on hydraulic fracturing practices. 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. In November 2018, voters rejected an initiative that would have materially restricted hydraulic fracturing activity in Colorado; however, the Colorado state legislature subsequently passed a package of hydraulic fracturing regulations in April 2019. In November 2019, the California governor's office imposed new regulations on hydraulic fracturing, including a moratorium on all new hydraulic fracturing permits pending review by a panel of scientists.

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. Additionally, the adoption of significant restrictions or a prohibition on hydraulic fracturing by a state, region or locality could result in a surplus of oilfield equipment in other states, regions or localities where hydraulic fracturing remains allowed.

Legislation and Regulation of Greenhouse Gases and Related Divestment and Other Efforts 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. 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 November 2019, the State Department formally informed the United Nations of the United States' withdrawal from the Paris Agreement. Due to the Paris Agreement's protocol, the withdrawal will be effective in November 2020. 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.

In addition to the regulatory efforts described above, there have also been efforts in recent years aimed at the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other groups, promoting the divestment of fossil fuel equities as well as to pressure lenders and other financial services companies to limit or curtail activities with companies engaged in the extraction of fossil fuel reserves. If these efforts are successful, our ability to access capital markets may be limited and our stock price may be negatively impacted.

Members of the investment community have recently increased their focus on sustainability practices with regard to the oil and gas industry, including practices related to GHGs and climate change. An increasing percentage of the investment community considers sustainability factors in making investment decisions, and an increasing number of our customers consider sustainability factors in awarding work. If we are unable to successfully continue our sustainability enhancement efforts, we may lose customers, our stock price may be negatively impacted, our reputation may be negatively affected, and it may be more difficult for us to effectively compete.

The Design, Manufacture, Sale and Servicing of Products, including Electrical Controls, 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 electrical controls, to customers involved in oil and gas exploration, development and production and in the marine and mining industries. Because of applications that 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 harm to our reputation, contractual and warranty-related liability, damage to the equipment, damage to the property of customers and others, personal injury and environmental contamination, leading to claims against us.

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. 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. Please see "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."

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, or a third party's infringement of our 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 customers or supplying vendors becomes involved in a dispute over infringement of intellectual property rights relating to equipment or technology owned or used by us, services performed by us or products provided by us, we may lose access to important equipment or technology or our ability to provide services or products, or we could be required to cease use of some equipment or technology or forced to modify our equipment, technology, services or products. We could also be required to pay license fees or royalties for the use of equipment or technology or provision of services or products. In addition, we may lose a competitive advantage in the event we are unsuccessful in enforcing our rights against third parties. Technology disputes involving us or our customers or supplying vendors could have a material adverse impact on our business, financial condition, cash flows 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. We also sell products, including electrical controls, for use in numerous oil and gas producing regions outside of North America, and through our Superior QC business, we occasionally provide remote data analytics and other services to customers to support their operations outside of the United States. 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 our services could be provided or where our consumers for 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.

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

We have borrowings outstanding under our senior notes and our term loan agreement and, from time to time, our revolving credit facility. Our ability to meet our interest and principal payment obligations depends in large part on cash flows from our subsidiaries. If our subsidiaries do not generate sufficient cash flows, 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 term loan facility under our Term Loan Agreement. Interest is paid on the outstanding principal amount of borrowings under the Term Loan Agreement at a floating rate based on, at our election, LIBOR or a base rate. The applicable margin on LIBOR rate loans varies from 1.00% to 1.375%, and the applicable margin on base rate loans varies from 0.00% to 0.375%, in each case determined based upon our credit rating. As of December 31, 2019, the applicable margin on LIBOR rate loans and base rate loans was 1.125% and 0.125%, respectively. As of December 31, 2019, we had $100 million in borrowings outstanding under the Term Loan Agreement.

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 1.00% to

2.00% and the applicable margin on base rate loans varies from 0.00% to 1.00%, in each case determined based upon our credit rating. As of December 31, 2019, the applicable margin on LIBOR rate loans was 1.50% and the applicable margin on base rate loans was 0.50%. As of December 31, 2019, we had no borrowings outstanding under our revolving credit facility.

Finally, 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, 2019, 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 at floating rates under these agreements or under future agreements.

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, industry conditions 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 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 debt agreements 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.

The Market Price of Our Common Stock May Be Highly Volatile, and Investors May Not Be Able to Resell Shares at or Above the Price Paid.

The trading price of our common stock may be volatile. Securities markets worldwide experience significant price and volume fluctuations. This market volatility, as well as other general economic, market or political conditions, could reduce the market price of our common stock in spite of our operating and/or financial performance. The following factors, in addition to other factors described in this “Risk Factors” section and elsewhere in this Report, may have a significant impact on the market price of our common stock:

- investor perception of us and the industry and markets in which we operate;
- general financial, domestic, international, economic, and market conditions, including overall fluctuations in the U.S. equity markets;
- increased focus by the investment community on sustainability practices at our company and in the oil and natural gas industry generally;

- changes in customer needs, expectations or trends and our ability to maintain relationships with key customers;
- our ability to implement our business strategy;
- changes in our capital structure, including the issuance of additional debt;
- public announcements (including the timing of these announcements) regarding our business, financial performance and prospects or new services or products, service or product enhancements, technological advances or strategic actions, such as acquisitions or divestitures, restructurings or significant contracts, by our competitors or us;
- trading activity in our stock, including portfolio transactions in our stock by us, our executive officers and directors, and significant stockholders or trading activity that results from the ordinary course rebalancing of stock indices in which we may be included;
- short-interest in our common stock, which could be significant from time to time;
- our inclusion in, or removal from, any stock indices;
- changes in earnings estimates or buy/sell recommendations by securities analysts;
- whether or not we meet earnings estimates of securities analysts who follow us; and
- regulatory or legal developments in the United States and foreign countries where we operate.

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.

As a Result of the SSE Merger, We Could Be Subject to Certain Contingent Tax Liabilities of Chesapeake Energy Corporation ("CHK") for Periods Prior to SSE's Spin-Off from CHK.

Under the Internal Revenue Code of 1986, as amended (the "Code"), and the related rules and regulations, each corporation (or its successor) 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 the SSE spin-off on June 30, 2014, is jointly and severally liable for the federal income tax liability of the entire consolidated tax reporting group for any such pre-spin-off taxable period during which it was a member of the group. According to CHK's public filings, CHK's federal examination cycles 2010 through 2015 were settled with the Internal Revenue Service during 2018, however, certain of these CHK taxable periods remain open for purposes of adjusting federal net operating loss carryforwards upon utilization. In connection with the SSE spin-off, SSE entered into a tax sharing agreement with CHK that generally provides that SSE is responsible for all taxes attributable to its business, whether accruing before, on or after the date of the spin-off, and CHK is responsible for any taxes attributable to the non-SSE businesses and for any taxes arising from the spin-off or certain related transactions that are imposed on SSE, CHK or its other subsidiaries. Notwithstanding such agreement, if CHK were unable to pay the taxes it is responsible for under such agreement, we (as the successor to SSE) could be required to pay the entire amount of such taxes under U.S. tax law, which could have a material adverse effect on us.

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, 2019, we had gross federal income tax NOLs of approximately $1.4 billion, approximately $247 million of which were assumed in connection with the SSE merger. 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. Any NOL arising prior to January 1, 2018 is subject to expiration 20 years after it arose. NOLs arising on or after January 1, 2018 are not subject to expiration.

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—our NOLs relating to SSE 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 prior to their expiration. Future changes in stock ownership or future regulatory changes could also limit our ability to utilize our NOLs. To the extent we are not able to offset future taxable income with 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 — 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, Ohio, West Virginia 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, and Montana.

Our oilfield rental operations are supported by offices and yard facilities located in Texas, Oklahoma and Ohio. Our servicing of equipment for drilling contractors is supported by offices and yard facilities located in Texas. Our electrical controls and automation operation is supported by an office and yard facility in 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, 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 5 of the Notes to Consolidated Financial Statements included in Item 8 of this Report.

Item 3. *Legal Proceedings.*

On July 18, 2018, OSHA issued a citation containing alleged violations, proposed abatement dates and an aggregate proposed penalty of approximately $74,000 in connection with an accident at a drilling site in Pittsburg County, Oklahoma that resulted in the losses of life of five people, including three of our employees. We filed a notice of contest with OSHA that contested all citation items, abatement dates and proposed penalties. The Department of Labor (the "DOL") filed a complaint on OSHA's behalf seeking enforcement of the citation as issued, and we filed an answer to the complaint. In October 2019, we and the DOL agreed to a settlement of all but one of the citation items, and a hearing on the remaining citation item was held before an administrative law judge. We and the DOL will file post-hearing briefs and await the judge's determination.

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, cash flows and results of operations.

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.

(b) Holders

As of February 7, 2020, there were approximately 1,000 holders of record of our common stock.

(c) Dividends

On February 5, 2020, our Board of Directors approved a cash dividend on our common stock in the amount of $0.04 per share to be paid on March 19, 2020 to holders of record as of March 5, 2020. 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, 2019.

Period Covered	Total Number of Shares Purchased (1)	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) (2)
October 2019	19,700	$8.49	—	$175,000
November 2019	840,922	$8.84	840,000	$167,576
December 2019	1,766,695	$9.96	1,764,987	$150,000
Total	2,627,317		2,604,987	$150,000

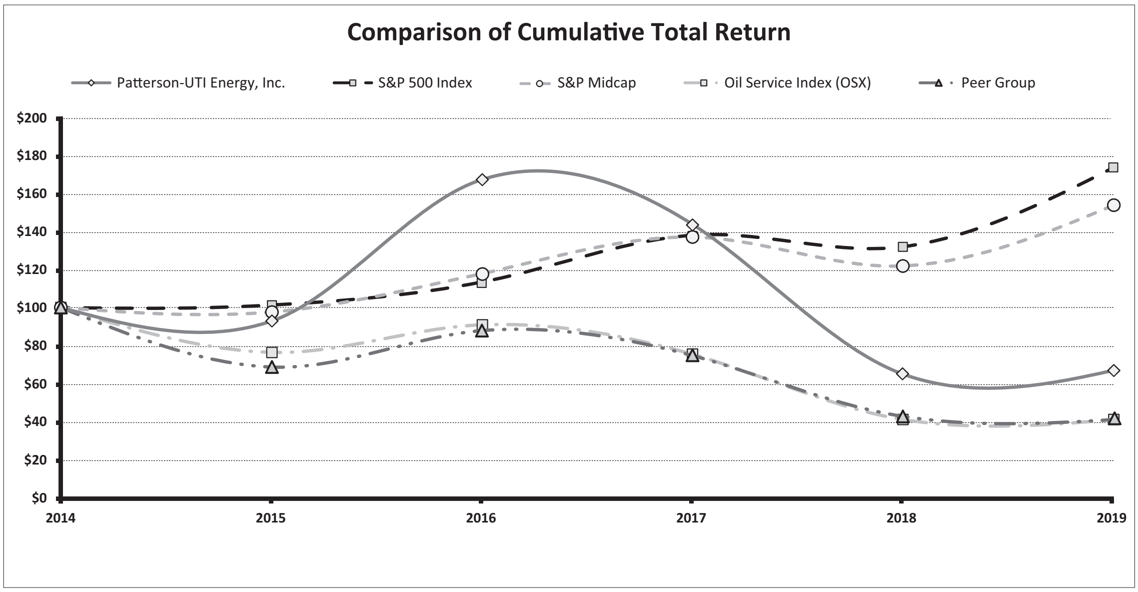
(1) We withheld 22,330 shares in the fourth quarter with respect to employees' tax withholding obligations upon the vesting of restricted stock and restricted stock units. These shares were acquired at fair market value pursuant to the terms of the Patterson-UTI Energy, Inc. Amended and Restated 2014 Long-Term Incentive Plan and not pursuant to the stock buyback program.

(2) 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. On July 26, 2018, we announced that our Board of Directors approved an increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. On February 7, 2019, we announced that our Board of Directors approved another increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. On July 25, 2019, we announced that our Board of Directors approved another increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. 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 buyback program are held as treasury shares. There is no expiration date associated with the buyback program.

(e) Performance Graph

The following graph compares the cumulative stockholder return of our common stock for the period from December 31, 2014 through December 31, 2019, with the cumulative total return of the S & P 500 Index, the S & P MidCap 400 Index, the Oilfield Service Index and a peer group determined by us. Our peer group consists of Basic Energy Services, Inc., Diamond Offshore Drilling Inc., 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, Superior Energy Services, Inc., TechnipFMC plc, Transocean Ltd., Unit Corp., Valaris plc and Weatherford International plc.

The graph assumes investment of $100 on December 31, 2014 and reinvestment of all dividends.



Company/Index	2014 ($)	2015 ($)	2016 ($)	2017 ($)	2018 ($)	2019 ($)
	Fiscal Year Ended December 31,					
Patterson-UTI Energy, Inc.	100.00	93.11	167.61	143.80	65.25	67.25
S&P 500 Stock Index	100.00	101.38	113.51	138.29	132.23	173.86
S&P MidCap Index	100.00	97.82	118.11	137.29	122.07	154.05
Oilfield Service Index	100.00	76.62	91.16	75.48	41.35	41.12
Peer Group Index	100.00	68.92	88.00	74.78	42.88	41.32

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, 2019, 2018, 2017, 2016, and 2015, and for each of the five years in the period ended December 31, 2019, 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 Current Power since October 25, 2018, the results of operations of Superior QC since February 20, 2018, the results of operations of MS Directional since October 11, 2017 and the results of operations of SSE since April 20, 2017.

	2019	2018	2017	2016	2015
		(In thousands, except per share amounts)			
Statement of Operations Data:					
Operating revenues:					
Contract drilling	$1,308,350	$1,430,492	$1,040,033	$ 543,663	$1,153,892
Pressure pumping	868,694	1,573,396	1,200,311	354,070	712,454
Directional drilling	188,786	209,275	45,580	—	—
Other	104,855	113,834	70,760	18,133	24,931
Total	2,470,685	3,326,997	2,356,684	915,866	1,891,277
Operating costs and expenses:					
Contract drilling	785,355	885,704	667,105	305,804	608,848
Pressure pumping	724,788	1,263,850	966,835	334,588	612,021
Directional drilling	178,645	175,829	32,172	—	—
Other	84,909	77,104	51,428	8,384	11,500
Depreciation, depletion, amortization and impairment	1,003,873	916,318	783,341	668,434	864,759
Impairment of goodwill	17,800	211,129	—	—	124,561
Selling, general and administrative	133,513	134,071	105,847	69,205	74,913
Provision for bad debt	5,683	—	—	—	—
Merger and integration expenses	—	2,738	74,451	—	—
Other operating (income) expense, net	(2,305)	(17,569)	(31,957)	(14,323)	1,647
Total	2,932,261	3,649,174	2,649,222	1,372,092	2,298,249
Operating loss	(461,576)	(322,177)	(292,538)	(456,226)	(406,972)
Other expense	(68,802)	(45,231)	(35,263)	(39,970)	(35,477)
Loss before income taxes	(530,378)	(367,408)	(327,801)	(496,196)	(442,449)
Income tax benefit	(104,675)	(45,987)	(333,711)	(177,562)	(147,963)
Net income (loss)	$ (425,703)	$ (321,421)	$ 5,910	$ (318,634)	$ (294,486)
Net income (loss) per common share:					
Basic	$ (2.10)	$ (1.47)	$ 0.03	$ (2.18)	$ (2.00)
Diluted	$ (2.10)	$ (1.47)	$ 0.03	$ (2.18)	$ (2.00)
Cash dividends per common share	$ 0.16	$ 0.14	$ 0.08	$ 0.16	$ 0.40
Weighted average number of common shares outstanding:					
Basic	203,039	218,643	198,447	146,178	145,416
Diluted	203,039	218,643	199,882	146,178	145,416
Balance Sheet Data:					
Total assets	$4,439,615	$5,469,866	$5,758,856	$3,772,291	$4,465,048
Borrowings under line of credit	—	—	268,000	—	—
Other long-term debt	966,540	1,119,205	598,783	598,437	787,900
Stockholders' equity	2,833,620	3,505,423	3,982,493	2,248,724	2,561,131
Working capital	231,213	423,881	200,605	(17,933)	178,887

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

Recent Developments — On November 15, 2019, we completed an offering of $350 million in aggregate principal amount of our 5.15% Senior Notes due November 15, 2029 (the "2029 Notes"). The net proceeds before offering expenses were approximately $347 million. On December 16, 2019, we used a portion of the net proceeds from the offering to prepay our 4.27% Series B Senior Notes due June 14, 2022 (the "Series B Notes"). The total amount of the prepayment, including the applicable "make-whole" premium, was approximately $315 million, plus accrued interest to the prepayment date. The remaining net proceeds and available cash on hand was used to repay $50 million of the borrowings under the Term Loan Agreement (as defined below).

On August 22, 2019, we entered into a term loan agreement (the "Term Loan Agreement") that permits a single borrowing of up to $150 million, which we drew in full on September 23, 2019. Subject to customary conditions, we may request that the lenders' aggregate commitments be increased by up to $75 million, not to exceed total commitments of $225 million. On September 25, 2019, we used $150 million of borrowings from the Term Loan Agreement and approximately $158 million of cash on hand to prepay our 4.97% Series A Senior Notes due October 5, 2020 (the "Series A Notes"). The total amount of the prepayment, including the applicable "make-whole" premium, was approximately $308 million, plus accrued interest to the prepayment date. We repaid $50 million of the borrowings under the Term Loan Agreement on December 16, 2019, and we had $100 million in outstanding borrowings under the Term Loan Agreement as of December 31, 2019.

On October 25, 2018, we acquired all of the issued and outstanding shares of Current Power Solutions, Inc. ("Current Power"). Current Power is a provider of electrical controls and automation to the energy, marine and mining industries. Operational and financial data in the discussion and analysis below includes the results of operations of the Current Power business in our other operations since October 25, 2018.

On March 27, 2018, we entered into an amended and restated credit agreement, which is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to $600 million, including a letter of credit facility that, at any time outstanding, is limited to $150 million and a swing line facility that, at any time outstanding, is limited to $20 million. See "Liquidity and Capital Resources."

On February 20, 2018, we acquired the business of Superior QC, LLC ("Superior QC"), including its assets and intellectual property. Superior QC is a provider of software and services used to improve the statistical accuracy of horizontal wellbore placement. Superior QC's measurement-while-drilling (MWD) Survey FDIR (fault detection, isolation and recovery) service is a data analytics technology to analyze MWD survey data in real-time and more accurately identify the position of a well. Operational and financial data in the discussion and analysis below includes the results of operations of the Superior QC business in our directional drilling segment since February 20, 2018.

On January 19, 2018, we completed an offering of $525 million in aggregate principal amount of our 3.95% Senior Notes due 2028 (the "2028 Notes"). We used $239 million of the net proceeds from the offering to repay amounts outstanding under our revolving credit facility.

Management Overview — We are a Houston, Texas-based oilfield services company that primarily owns and operates one of the largest fleets of land-based drilling rigs in the United States and a large fleet of pressure pumping equipment. Our contract drilling business operates in the continental United States and western Canada, and, from time to time, we pursue 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, and we provide services that improve the statistical accuracy of horizontal wellbore placement. We have other operations through which we provide oilfield rental tools in select markets in the United States. We also service equipment for drilling contractors, and we provide electrical controls and automation to the energy, marine and mining industries 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.

Oil prices have recovered from a 12-year low of $26.19 in February 2016 and reached a high of $77.41 in June 2018. Oil prices remain volatile, as the closing price of oil began the year at a low of $46.31 per barrel on January 2, 2019, before increasing by 43% over the course of four months to reach a high of $66.24 per barrel in late April 2019. Since May 2019, oil prices have generally ranged between $50 and $60 per barrel. Oil prices averaged $56.94 per barrel in the fourth quarter of 2019 and closed at $50.06 per barrel on February 3, 2020. Quarterly average oil prices and our quarterly average number of rigs operating in the United States for 2017, 2018, and 2019 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
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
2018:				
Average oil price per Bbl(1)	$62.88	$68.04	$69.76	$59.08
Average rigs operating per day—U.S.(2)	166	175	177	182
2019:				
Average oil price per Bbl(1)	$54.83	$59.78	$56.37	$56.94
Average rigs operating per day—U.S.(2)	174	157	142	122

(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.

Our rig count declined significantly during the industry downturn that began in late 2014, improved following the second quarter of 2016, and has declined since the fourth quarter of 2018. Our average active rig count for the fourth quarter of 2019 was 123 rigs, which included 122 rigs in the United States and less than one rig operating in Canada. This was a decrease from our average active rig count for the third quarter of 2019 of 142 rigs, which included 142 rigs in the United States and less than one rig in Canada. Our rig count in the United States at December 31, 2019 of 121 rigs was less than the rig count of 183 rigs at December 31, 2018. Term contracts have supported our operating rig count during the last three years. Based on contracts currently in place, we expect an average of 77 rigs operating under term contracts during the first quarter of 2020 and an average of 58 rigs operating under term contracts throughout 2020.

The pressure pumping market showed signs of oversupply in the second half of 2018 and was oversupplied in 2019. In response to oversupplied market conditions, we reduced the number of active pressure pumping spreads to 11 as of the end of 2019. We expect to average ten active pressure pumping spreads during the first quarter of 2020.

Our revenues, profitability and cash flows are highly dependent upon prevailing prices for oil and natural gas and upon our customers' ability to access capital to fund their operating and capital expenditures. During periods of improved oil and natural gas 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 oil and natural gas prices deteriorate or when our customers have a reduced ability to access capital, the demand for our services generally weakens, and we experience downward pressure on pricing for our services.

The North American oil and natural gas services industry is cyclical and at times experiences downturns in demand. During these periods, there has been substantially more oil and natural gas service equipment available than necessary to meet demand. As a result, oil and natural gas service contractors have had difficulty sustaining profit margins and, at times, have incurred losses during the downturn periods. Currently, there is an excess supply of drilling rigs, pressure pumping equipment and directional drilling equipment. We cannot predict either the future level of demand for our oil and natural gas services or future conditions in the oil and natural gas service businesses.

We are highly impacted by operational risks, competition, labor issues, weather, the availability of products used in our pressure pumping business, supplier delays and various other factors that could materially adversely affect our business, financial condition, cash flows and results of operations. See “Risk Factors” in Item 1A of this Report.

For the three years ended December 31, 2019, our operating revenues consisted of the following (dollars in thousands):

	2019		2018		2017	
Contract drilling	$1,308,350	53.0%	$1,430,492	43.0%	$1,040,033	44.1%
Pressure pumping	868,694	35.2%	1,573,396	47.3%	1,200,311	50.9%
Directional drilling	188,786	7.6%	209,275	6.3%	45,580	1.9%
Other	104,855	4.2%	113,834	3.4%	70,760	3.1%
	$2,470,685	100.0%	$3,326,997	100.0%	$2,356,684	100.0%

Contract Drilling

Contract drilling revenues accounted for 53.0% of our consolidated 2019 revenues and decreased 8.5% from 2018.

We have addressed our customers’ needs for drilling horizontal wells in shale and other unconventional resource plays by improving the capabilities of our drilling fleet during the last several years. The U.S. land rig industry refers 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 at least a 750,000-pound hookload, a 7,500-psi circulating system, and is pad-capable. As of December 31, 2019, our rig fleet included 198 APEX® rigs, of which 150 were super-spec rigs.

We maintain a backlog of commitments for contract drilling services under term contracts, which we define as contracts with a duration of six months or more. Our contract drilling backlog as of December 31, 2019 and 2018 was approximately $605 million and $770 million, respectively. Approximately 28% of the total contract drilling backlog at December 31, 2019 is reasonably expected to remain after 2020. 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 fees for other services such as for mobilization, other than initial 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. For contracts that contain variable dayrate pricing, our backlog calculation uses the dayrate in effect for periods where the dayrate is fixed, and, for periods that remain subject to variable pricing, uses the commodity price in effect at December 31, 2019. 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 on which we have received an early termination notice, our backlog calculation includes the early termination rate, instead of the dayrate, for the period over which we expect to receive the lower rate. See “Item 1A. Risk Factors – 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.”

Ongoing factors which could continue to adversely affect utilization rates and pricing, even in an environment of high oil and natural gas prices and increased drilling activity, include:

- movement of drilling rigs from region to region,
- reactivation of drilling rigs,
- refurbishment and upgrades of existing drilling rigs,

- development of new technologies that enhance drilling efficiency, and
- construction of new technology drilling rigs.

Pressure Pumping

Pressure pumping revenues accounted for 35.2% of our consolidated 2019 revenues and decreased 44.8% from 2018. As of December 31, 2019, we had approximately 1.4 million horsepower in our pressure pumping fleet. The pressure pumping market showed signs of oversupply in the second half of 2018 and was oversupplied in 2019. In response to oversupplied market conditions, we reduced the number of active pressure pumping spreads to 11 as of the end of the fourth quarter of 2019. We expect to average ten active pressure pumping spreads during the first quarter of 2020.

Directional Drilling

Directional drilling revenues accounted for 7.6% of our consolidated 2019 revenues and decreased 9.8% from 2018. Activity for directional drilling commenced with the acquisition of MS Directional, LLC (f/k/a Multi-Shot, LLC) ("MS Directional") in October 2017, which provides 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, measurement-while-drilling, and wireline steering tools, and we provide services that improve the statistical accuracy of horizontal wellbore placement.

Other Operations

Other operations revenues accounted for 4.2% of our consolidated 2019 revenues and decreased 7.9% from 2018. Our oilfield rentals business, with a fleet of premium oilfield rental tools, provides the largest revenue contribution to our other operations and provides specialized services for land-based oil and natural gas drilling, completion and workover activities. Other operations also includes the results of our electrical controls and automation business, the results of our drilling equipment service business, and the results of our ownership, as a non-operating working interest owner, in oil and natural gas assets that are primarily located in Texas and New Mexico.

Capital Expenditures

Cash capital expenditures for 2019 totaled $348 million. For 2020, based on near-term activity levels, we expect cash used for capital expenditures to be approximately $250 million.

For the three years ended December 31, 2019, our operating income (loss) consisted of the following (dollars in thousands):

	2019		2018		2017	
Contract drilling	$(151,329)	32.8%	$ (33,115)	10.3%	$(171,897)	58.8%
Pressure pumping	(102,701)	22.3%	(77,328)	24.0%	21,028	(7.2)%
Directional drilling	(52,724)	11.4%	(117,497)	36.5%	(21)	—%
Other	(54,725)	11.9%	(18,221)	5.7%	(20,813)	7.1%
Corporate	(100,097)	21.6%	(76,016)	23.5%	(120,835)	41.3%
	$(461,576)	100.0%	$(322,177)	100.0%	$(292,538)	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.

Lower demand for our contract drilling and pressure pumping services in 2019, an impairment of goodwill and write-downs to drilling and pressure pumping equipment and an increase in interest expense due to the 2019 prepayment of the Series A Notes and Series B Notes contributed to a consolidated net loss of $426 million for 2019, compared to a consolidated net loss of $321 million for 2018 and consolidated net income of $5.9 million for 2017. Our net income for 2017 was positive due to the 2017 tax law change.

Results of Operations

Comparison of the years ended December 31, 2019 and 2018

The following tables summarize results of operations by business segment for the years ended December 31, 2019 and 2018:

Contract Drilling	Year Ended December 31, 2019	2018	% Change
	(Dollars in thousands)		
Revenues	$1,308,350	$1,430,492	(8.5)%
Direct operating costs	785,355	885,704	(11.3)%
Margin (1)	522,995	544,788	(4.0)%
Selling, general and administrative	6,317	6,296	0.3%
Depreciation, amortization and impairment	668,007	571,607	16.9%
Operating loss	$ (151,329)	$ (33,115)	357.0%
Operating days	54,544	64,479	(15.4)%
Average revenue per operating day	$ 23.99	$ 22.19	8.1%
Average direct operating costs per operating day	$ 14.40	$ 13.74	4.8%
Average margin per operating day (1)	$ 9.59	$ 8.45	13.5%
Average rigs operating	149.4	176.7	(15.4)%
Capital expenditures	$ 194,416	$ 394,595	(50.7)%

(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.

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 2019, our average number of rigs operating was 149, compared to 177 in 2018. Our average rig revenue per operating day was $23,990 in 2019, compared to $22,190 in 2018. Our average revenue per operating day is largely dependent on the pricing terms of our rig contracts.

Revenues and direct operating costs decreased in 2019 primarily due to a decrease in operating days. Average revenue per operating day increased in 2019. This increase was supported by our upgrades of additional rigs to super-spec capability.

Depreciation, amortization and impairment for 2019 included a charge of $173 million related to the retirement of 36 legacy non-APEX® drilling rigs and related equipment. Depreciation, amortization and impairment for 2018 included a charge of $48.4 million related to the retirement of 42 legacy non-APEX® drilling rigs and related equipment.

Capital expenditures decreased in 2019 primarily due to upgrading more rigs to super-spec capability in 2018 relative to 2019.

	Year Ended December 31,		
Pressure Pumping	**2019**	**2018**	**% Change**
	(Dollars in thousands)		
Revenues	$ 868,694	$1,573,396	(44.8)%
Direct operating costs	724,788	1,263,850	(42.7)%
Margin (1)	143,906	309,546	(53.5)%
Selling, general and administrative	12,655	15,420	(17.9)%
Depreciation, amortization and impairment	233,952	250,010	(6.4)%
Impairment of goodwill	—	121,444	NA
Operating loss	$(102,701)	$ (77,328)	32.8%
Fracturing jobs	505	812	(37.8)%
Other jobs	844	1,081	(21.9)%
Total jobs	1,349	1,893	(28.7)%
Average revenue per fracturing job	$1,673.81	$ 1,909.42	(12.3)%
Average revenue per other job	$ 27.75	$ 21.23	30.7%
Average revenue per total job	$ 643.95	$ 831.17	(22.5)%
Average direct operating costs per total job	$ 537.28	$ 667.64	(19.5)%
Average margin per total job (1)	$ 106.68	$ 163.52	(34.8)%
Margin as a percentage of revenues (1)	16.6%	19.7%	(15.7)%
Capital expenditures	$ 105,803	$ 173,848	(39.1)%

(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.

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. Direct operating costs are also most impacted by these same factors. Our average revenue per fracturing job is largely dependent on the pricing terms of our pressure pumping contracts. We completed 505 fracturing jobs during 2019 compared to 812 fracturing jobs in 2018. Our average revenue per fracturing job was $1.674 million in 2019 compared to $1.909 million in 2018.

Revenues and direct operating costs decreased in 2019 primarily due to a decline in the number of fracturing jobs. Average revenue and direct operating costs per job were impacted by lower demand, more customers self-sourcing products and decreases in product prices.

Selling, general and administrative expenses decreased primarily as a result of cost reduction efforts.

Depreciation, amortization and impairment expense included charges of $20.5 million and $17.4 million related to the write-down of pressure pumping equipment in 2019 and 2018, respectively. All of the goodwill associated with our pressure pumping business was impaired during 2018. See Note 6 of Notes to Consolidated Financial Statements for additional information.

The decrease in capital expenditures was primarily due to higher maintenance capital expenditures in 2018 when activity levels were higher.

Directional Drilling	Year Ended December 31, 2019	2018	% Change
	(Dollars in thousands)		
Revenues	$188,786	$ 209,275	(9.8)%
Direct operating costs	178,645	175,829	1.6%
Margin (1)	10,141	33,446	(69.7)%
Selling, general and administrative	10,642	15,941	(33.2)%
Depreciation and amortization	52,223	45,317	15.2%
Impairment of goodwill	—	89,685	NA
Operating loss	$ (52,724)	$(117,497)	(55.1)%
Capital expenditures	$ 15,549	$ 35,929	(56.7)%

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

Directional drilling revenue decreased by $20.5 million from 2018 primarily due to decreased job activity, partially offset by increased revenue from Superior QC, which was acquired in the first quarter of 2018.

Direct operating costs for 2019 included a charge of $17.0 million primarily due to the write-down of inventory, partially offset by lower operating costs due to decreased job activity.

Selling, general and administrative expense decreased from 2018 primarily as a result of cost reduction efforts.

Depreciation, amortization and impairment for 2019 included a charge of $8.4 million related to the write-down of directional drilling equipment. There were no similar charges in 2018.

The decrease in capital expenditures was primarily due to higher capital expenditures in 2018 in response to market demand for equipment upgrades.

Other Operations	Year Ended December 31, 2019	2018	% Change
	(Dollars in thousands)		
Revenues	$104,855	$113,834	(7.9)%
Direct operating costs	84,909	77,104	10.1%
Margin (1)	19,946	36,730	(45.7)%
Selling, general and administrative	14,068	13,439	4.7%
Depreciation, depletion, amortization and impairment	42,803	41,512	3.1%
Impairment of goodwill	17,800	—	NA
Operating loss	$ (54,725)	$ (18,221)	200.3%
Capital expenditures	$ 27,132	$ 34,660	(21.7)%

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

Other operations revenue decreased primarily due to a decline in revenue in our oilfield rentals business.

During the third quarter of 2019, we made the decision to transition away from our engineering and manufacturing efforts in Calgary. Direct operating costs and selling, general and administrative costs for 2019 include $12.4 million and $2.2 million, respectively, of charges associated with this decision. The $12.4 million of charges to direct operating costs is primarily comprised of inventory write-offs.

All of the goodwill associated with our oilfield rentals and electrical controls and automation reporting units was impaired during 2019.

The decrease in capital expenditures was primarily due to 2018 investments in the oilfield rentals business.

Corporate	Year Ended December 31, 2019	2018	% Change
	(Dollars in thousands)		
Selling, general and administrative	$ 89,831	$ 82,975	8.3%
Merger and integration expenses	$ —	$ 2,738	NA
Depreciation	$ 6,888	$ 7,872	(12.5)%
Other operating (income) expense, net			
Net gain on asset disposals	$(13,904)	$(28,958)	(52.0)%
Legal-related expenses and settlements, net of insurance reimbursements	(3,471)	12,684	NA
Research and development	3,840	3,444	11.5%
Other	11,230	(4,739)	NA
Other operating income, net	$ (2,305)	$(17,569)	(86.9)%
Provision for bad debts	$ 5,683	$ —	NA
Interest income	$ 6,013	$ 5,597	7.4%
Interest expense	$ 75,204	$ 51,578	45.8%
Other income	$ 389	$ 750	(48.1)%
Capital expenditures	$ 4,612	$ 2,426	90.1%

Selling, general and administrative expense increased in 2019 due to an increase in compensation related expenses. Merger and integration expenses incurred in 2018 are related to the Seventy Seven Energy Inc. merger (the "SSE merger"), MS Directional acquisition and Superior QC acquisition.

Other operating expenses (income), net 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 majority of the net gain on asset disposals during 2019 reflects gains on disposal of drilling equipment. Legal-related expenses and settlements in 2018 includes insurance deductibles and investigation costs related to an accident at a drilling site in January 2018. Legal-related expenses and settlements in 2019 includes proceeds from insurance claims. Other operating expenses (income), net includes a $12.7 million charge recorded in 2019 related to a 2017 capacity reservation agreement that required a cash deposit to increase our access to finer grades of sand for our pressure pumping business. As market prices for sand substantially decreased since 2017, we purchased lower cost sand outside of this capacity reservation contract and revalued the deposit at its expected realizable value. Other operating expenses (income), net includes a gain recorded in 2018 related to the collection of a note receivable that had been recorded at a discount.

A provision for bad debts was recognized in 2019 with respect to accounts receivable balances that were estimated to be uncollectible. Interest expense includes a loss on early debt extinguishment of $24.0 million in 2019 as a result of prepayment of the Series A Notes and Series B Notes.

Results of Operations

Comparison of the years ended December 31, 2018 and 2017

The following tables summarize results of operations by business segment for the years ended December 31, 2018 and 2017:

Contract Drilling	Year Ended December 31, 2018	2017	% Change
	(Dollars in thousands)		
Revenues	$1,430,492	$1,040,033	37.5%
Direct operating costs	885,704	667,105	32.8%
Margin (1)	544,788	372,928	46.1%
Selling, general and administrative	6,296	5,934	6.1%
Depreciation, amortization and impairment	571,607	538,891	6.1%
Operating loss	$ (33,115)	$ (171,897)	(80.7)%
Operating days	64,479	50,427	27.9%
Average revenue per operating day	$ 22.19	$ 20.62	7.6%
Average direct operating costs per operating day	$ 13.74	$ 13.23	3.9%
Average margin per operating day (1)	$ 8.45	$ 7.40	14.2%
Average rigs operating	$ 176.7	$ 138.2	27.9%
Capital expenditures	$ 394,595	$ 354,425	11.3%

(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.

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 2018, our average number of rigs operating was 175 in the United States and one in Canada, compared to 136 in the United States and two in Canada in 2017. Our average rig revenue per operating day was $22,190 in 2018, compared to $20,620 in 2017. Our average revenue per operating day is largely dependent on the pricing terms of our rig contracts.

Revenues and direct operating costs increased primarily due to an increase in operating days. Operating days and average rigs operating increased in 2018 primarily due to the recovery in the oil and natural gas industry, the contribution of rigs acquired in the SSE merger and the contribution from rigs that have been upgraded to super-spec capability. Capital expenditures increased in 2018 due to the upgrade of rigs to super-spec capability, higher maintenance capital expenditures and other equipment upgrades. Depreciation, amortization and impairment for 2018 included a charge of $48.4 million related to the retirement of 42 legacy non-APEX® rigs and related equipment. Based on the strong customer preference across the industry for super-spec drilling rigs, we believe the 42 rigs that were retired had limited commercial opportunity. Depreciation, amortization and impairment for 2017 included a 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.

Pressure Pumping	Year Ended December 31, 2018	2017	% Change
	(Dollars in thousands)		
Revenues	$1,573,396	$1,200,311	31.1%
Direct operating costs	1,263,850	966,835	30.7%
Margin (1)	309,546	233,476	32.6%
Selling, general and administrative	15,420	14,442	6.8%
Depreciation, amortization and impairment	250,010	198,006	26.3%
Impairment of goodwill	121,444	—	NA
Operating income (loss)	$ (77,328)	$ 21,028	NA
Fracturing jobs	812	622	30.5%
Other jobs	1,081	1,262	(14.3)%
Total jobs	1,893	1,884	0.5%
Average revenue per fracturing job	$ 1,909.42	$ 1,894.40	0.8%
Average revenue per other job	$ 21.23	$ 17.43	21.8%
Average revenue per total job	$ 831.17	$ 637.11	30.5%
Average direct operating costs per total job	$ 667.64	$ 513.18	30.1%
Average margin per total job (1)	$ 163.52	$ 123.93	31.9%
Margin as a percentage of revenues (1)	19.7%	19.5%	1.0%
Capital expenditures	$ 173,848	$ 171,436	1.4%

(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.

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 812 fracturing jobs during 2018 compared to 622 fracturing jobs in 2017. Our average revenue per fracturing job was $1.909 million in 2018 compared to $1.894 million in 2017.

Revenues and direct operating costs in 2018 increased primarily due to an increase in the number of fracturing jobs. Depreciation, amortization and impairment expense increased due to the assets acquired in the SSE merger. Also included in depreciation, amortization and impairment expense for 2018 is a charge of $17.4 million related to the write-down of obsolete sand-handling equipment. There was no similar charge in the comparable period of 2017. All of the goodwill associated with our pressure pumping business was impaired during 2018. See Note 6 of Notes to Consolidated Financial Statements for additional information.

Directional Drilling	Year Ended December 31, 2018	2017	% Change
	(Dollars in thousands)		
Revenues	$ 209,275	$45,580	359.1%
Direct operating costs	175,829	32,172	446.5%
Margin (1)	33,446	13,408	149.4%
Selling, general and administrative	15,941	4,082	290.5%
Depreciation and amortization	45,317	9,347	384.8%
Impairment of goodwill	89,685	—	NA
Operating loss	$(117,497)	$ (21)	NA
Capital expenditures	$ 35,929	$ 7,795	360.9%

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

Our directional drilling segment originated with the October 11, 2017 acquisition of MS Directional, and consequently the results for 2017 include less than three months of operations. Margins in 2018 were negatively impacted by higher third-party rental expenses due to delays in the delivery of equipment and by higher repairs and maintenance costs. All of the goodwill associated with our directional drilling business was impaired during 2018. See Note 6 of Notes to Consolidated Financial Statements for additional information.

Other Operations	Year Ended December 31, 2018	2017	% Change
	(Dollars in thousands)		
Revenues	$113,834	$ 70,760	60.9%
Direct operating costs	77,104	51,428	49.9%
Margin (1)	36,730	19,332	90.0%
Selling, general and administrative	13,439	10,743	25.1%
Depreciation, depletion, amortization and impairment	41,512	29,402	41.2%
Operating loss	$ (18,221)	$(20,813)	(12.5)%
Capital expenditures	$ 34,660	$ 31,547	9.9%

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

Revenues, direct operating costs, and depreciation, depletion, amortization and impairment expense from other operations increased primarily as a result of the inclusion of our oilfield rentals business acquired in the SSE merger on April 20, 2017. The increase in capital expenditures was due to investments in the oilfield rentals business.

Corporate	Year Ended December 31,		
	2018	2017	% Change
	(Dollars in thousands)		
Selling, general and administrative	$ 82,975	$ 70,646	17.5%
Merger and integration expenses	$ 2,738	$ 74,451	(96.3)%
Depreciation	$ 7,872	$ 7,695	2.3%
Other operating (income) expense, net			
Net gain on asset disposals	$(28,958)	$(33,510)	(13.6)%
Legal-related expenses and settlements, net of insurance reimbursements	12,684	561	NA
Research and development	3,444	1,002	243.7%
Other	(4,739)	(10)	NA
Other operating income, net	$(17,569)	$(31,957)	(45.0)%
Interest income	$ 5,597	$ 1,866	199.9%
Interest expense	$ 51,578	$ 37,472	37.6%
Other income	$ 750	$ 343	118.7%
Capital expenditures	$ 2,426	$ 1,884	28.8%

Selling, general and administrative expense increased in 2018, but as a percentage of consolidated revenues decreased to 2.5%, compared to 3.0% in 2017. Selling, general and administrative expense increased in 2018 primarily due to the personnel added as a result of the SSE merger. Merger and integration expenses incurred in 2018 are related to the SSE merger, the MS Directional acquisition and the Superior QC acquisition. Merger and integration expenses incurred in 2017 are related to the SSE merger and the 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 majority of the net gain on asset disposals during the 2018 period reflects gains on disposal of drilling equipment. The 2017 period included a gain of $11.2 million related to the sale of real estate. Legal-related expenses and settlements in 2018 includes insurance deductibles and investigation costs related to an accident at a drilling site in January 2018. Research and development expense during 2018 and 2017 relate primarily to the funding of research into pressure pumping technology. Other operating income during 2018 also includes the gain on the collection of a note receivable that had previously been discounted. Interest income increased in 2018 due to interest earned on the portion of the proceeds of the January 2018 debt offering that were held as cash during 2018. The debt offering also resulted in an increase in interest expense for 2018.

Income Taxes

	Year Ended December 31,		
	2019	2018	2017
	(Dollars in thousands)		
Loss before income taxes	$(530,378)	$(367,408)	$(327,801)
Income tax benefit	$(104,675)	$ (45,987)	$(333,711)
Effective tax rate	19.7%	12.5%	101.8%

The difference between the statutory federal income tax rate and the effective income tax rate for the years ended December 31, 2019, 2018 and 2017 is summarized as follows:

	2019	2018	2017
Statutory tax rate	21.0%	21.0%	35.0%
State income taxes—net of the federal income tax benefit	1.7	1.2	1.9
Goodwill impairment	(0.7)	(6.9)	—
Permanent differences	(0.5)	(0.6)	(1.3)
Tax effects of tax reform	—	(1.3)	66.7
Share-based payments	(0.7)	(0.1)	3.6
Acquisition related differences	—	—	(3.3)
Valuation allowance	(0.8)	(3.7)	—
State deferred tax remeasurement	(1.1)	2.3	—
Other differences, net	0.8	0.6	(0.8)
Effective tax rate	19.7%	12.5%	101.8%

The effective tax rate increased by approximately 7.2% to 19.7% for 2019 compared to 12.5% for 2018. This difference was primarily due to higher goodwill impairment charges in 2018 relative to 2019, which are not deductible for tax purposes. These charges resulted in a 6.9% decrease to the effective tax rate in 2018, as compared to a 0.7% decrease to the effective tax rate in 2019. Another factor was valuation allowances being established against deferred tax assets in certain state and non-U.S. jurisdictions, which were higher in 2018 as compared to 2019. These resulted in a 3.7% decrease to the effective tax rate in 2018, as compared to a 0.8% decrease to the rate in 2019.

We continue to monitor income tax developments in the United States and other countries affecting the Company. In December 2017, the United States enacted U.S. Tax Reform, which materially impacted the consolidated financial statements by decreasing the U.S. corporate statutory tax rate and significantly affecting future periods. We expect several proposed U.S. Treasury regulations under U.S. Tax Reform that were issued during 2018 and 2019 to be finalized during 2020. We will incorporate into our future financial statements the impacts, if any, of these regulations and additional authoritative guidance when finalized.

We continue to elect permanent reinvestment of unremitted earnings in Canada effective January 1, 2010, and we intend to do so for the foreseeable future. If we were to repatriate earnings, in the form of dividends or otherwise, it might be subject to certain income taxes (subject to an adjustment for foreign tax credits) and withholding taxes payable.

Liquidity and Capital Resources

Our liquidity as of December 31, 2019 included approximately $231 million in working capital, including $174 million of cash and cash equivalents, and approximately $600 million available under our revolving credit facility.

On January 19, 2018, we completed an offering of $525 million in aggregate principal amount of our 2028 Notes. We used $239 million of the net proceeds from the offering to repay amounts outstanding under our revolving credit facility. As described below, on March 27, 2018, we entered into an amended and restated credit agreement, which is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to $600 million, including a letter of credit facility that, at any time outstanding, is limited to $150 million and a swing line facility that, at any time outstanding, is limited to $20 million.

On August 22, 2019, we entered into the Term Loan Agreement, which permits a single borrowing of up to $150 million, which we drew in full on September 23, 2019. Subject to customary conditions, we may request that the lenders' aggregate commitments be increased by up to $75 million, not to exceed total commitments of

$225 million. On September 25, 2019, we used $150 million of borrowings from the Term Loan Agreement and approximately $158 million of cash on hand to prepay the Series A Notes. The total amount of the prepayment, including the applicable "make-whole" premium, was approximately $308 million, plus accrued interest to the prepayment date. We repaid $50 million of the borrowings under the Term Loan Agreement on December 16, 2019, and we had $100 million in outstanding borrowings under the Term Loan Agreement as of December 31, 2019.

On November 15, 2019, we completed an offering of $350 million in aggregate principal amount of the 2029 Notes. The net proceeds before offering expenses were approximately $347 million. On December 16, 2019, we used a portion of the net proceeds from the offering to prepay the Series B Notes. The total amount of the prepayment, including the applicable "make-whole" premium, was approximately $315 million, plus accrued interest to the prepayment date. The remaining net proceeds and available cash on hand was used to repay $50 million of the borrowings under the Term Loan Agreement.

We believe our current liquidity, together with cash expected to be generated from operations, 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, 2019, we had working capital of $231 million, including cash and cash equivalents of $174 million, compared to working capital of $424 million, including cash and cash equivalents of $245 million, at December 31, 2018.

During 2019, our sources of cash flow included:

- $696 million from operating activities,
- $45.8 million in proceeds from the disposal of property and equipment and insurance proceeds, and
- $497 million in proceeds from the issuance of long-term debt.

During 2019, we used $32.4 million to pay dividends on our common stock, $255 million for repurchases of our common stock, $308 million for the prepayment of the Series A Notes, $315 million for the prepayment of the Series B Notes, $50 million for the repayment of borrowings under the Term Loan Agreement and $348 million:

- to make capital expenditures for the acquisition, betterment and refurbishment of drilling rigs and pressure pumping equipment and, to a much lesser extent, equipment for our other businesses,
- to acquire and procure equipment and facilities to support our drilling, pressure pumping, directional drilling, oilfield rentals 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, 2019 as follows:

	Per Share	Total (in thousands)
Paid on March 21, 2019	$0.04	$ 8,499
Paid on June 20, 2019	0.04	8,344
Paid on September 19, 2019	0.04	7,847
Paid on December 19, 2019	0.04	7,738
Total cash dividends	$0.16	$32,428

On February 5, 2020, our Board of Directors approved a cash dividend on our common stock in the amount of $0.04 per share to be paid on March 19, 2020 to holders of record as of March 5, 2020. 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 authorized purchases of up to $200 million of our common stock in open market or privately negotiated transactions. On July 25, 2018, our Board of Directors approved an increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. On February 6, 2019, our Board of Directors approved another increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. On July 24, 2019, our Board of Directors approved another increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. 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 buyback program are held as treasury shares. There is no expiration date associated with the buyback program. As of December 31, 2019, we had remaining authorization to purchase approximately $150 million of our outstanding common stock under the stock buyback program.

We acquired shares of stock from directors in 2017 and employees during 2019, 2018, and 2017 that are accounted for as treasury stock. Certain of these shares were acquired to satisfy the exercise price and employees' tax withholding obligations upon 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 and restricted stock units. These shares were acquired at fair market value. These acquisitions were made pursuant to the terms of the Patterson-UTI Energy, Inc. Amended and Restated 2014 Long-Term Incentive Plan and not pursuant to the stock buyback program.

Treasury stock acquisitions during the years ended December 31, 2019, 2018 and 2017 were as follows (dollars in thousands):

	2019		2018		2017	
	Shares	**Cost**	**Shares**	**Cost**	**Shares**	**Cost**
Treasury shares at beginning of period	53,701,096	$1,080,448	43,802,611	$ 918,711	43,392,617	$911,094
Purchases pursuant to stock buyback program	22,566,331	250,109	9,331,131	150,497	5,503	109
Acquisitions pursuant to long-term incentive plan	1,037,947	14,205	567,354	11,240	404,491	7,508
Other	31,013	372	—	—	—	—
Treasury shares at end of period	77,336,387	$1,345,134	53,701,096	$1,080,448	43,802,611	$918,711

2019 Term Loan Agreement — On August 22, 2019, we entered into the Term Loan Agreement among us, as borrower, Wells Fargo Bank, National Association, as administrative agent and lender and the other lender party thereto.

The Term Loan Agreement is a committed senior unsecured term loan facility that permits a single borrowing of up to $150 million, which we drew in full on September 23, 2019. Subject to customary conditions, we may request that the lenders' aggregate commitments be increased by up to $75 million, not to exceed total commitments of $225 million. The maturity date under the Term Loan Agreement is June 10, 2022. We repaid $50 million of the borrowings under the Term Loan Agreement on December 16, 2019.

Loans under the Term Loan Agreement bear interest by reference, at our election, to the LIBOR rate or base rate. The applicable margin on LIBOR rate loans varies from 1.00% to 1.375%, and the applicable margin on base rate loans varies from 0.00% to 0.375%, in each case determined based upon our credit rating. As of December 31, 2019, the applicable margin on LIBOR rate loans and base rate loans was 1.125% and 0.125%, respectively.

The Term Loan Agreement contains representations, warranties, affirmative and negative covenants and events of default and associated remedies that we believe are customary for agreements of this nature, including certain restrictions on our ability and each of our subsidiaries to incur debt and grant liens. If our credit rating is below investment grade, we will become subject to a restricted payment covenant, which would require us to have a Pro Forma Debt Service Coverage Ratio (as defined in the Term Loan Agreement) greater than or equal to 1.50 to 1.00 immediately before and immediately after making any restricted payment.

The Term Loan Agreement requires mandatory prepayment in an amount equal to 100% of the net cash proceeds from the issuance of new senior indebtedness (other than certain permitted indebtedness) if our credit rating is below investment grade. The Term Loan Agreement also requires that our total debt to capitalization ratio, expressed as a percentage, not exceed 50%. The Term Loan Agreement generally defines the total 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 end of the most recently ended fiscal quarter.

As of December 31, 2019, we had $100 million in borrowings outstanding under the Term Loan Agreement at a LIBOR interest rate of 2.917%.

Credit Agreement — On March 27, 2018, we entered into an amended and restated credit agreement (the "Credit Agreement") among us, as borrower, Wells Fargo Bank, National Association, as administrative agent, letter of credit issuer, swing line lender and lender, each of the other lenders and letter of credit issuers party thereto, The Bank of Nova Scotia and U.S. Bank National Association, as Co-Syndication Agents, Royal Bank of Canada, as Documentation Agent and Wells Fargo Securities, LLC, The Bank of Nova Scotia and U.S. Bank National Association, as Co-Lead Arrangers and Joint Book Runners.

The Credit Agreement is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to $600 million, including a letter of credit facility that, at any time outstanding, is limited to $150 million and a swing line facility that, at any time outstanding, is limited to $20 million. Subject to customary conditions, we may request that the lenders' aggregate commitments be increased by up to $300 million, not to exceed total commitments of $900 million. The original maturity date under the Credit Agreement was March 27, 2023. On March 26, 2019, we entered into Amendment No. 1 to Amended and Restated Credit Agreement, which amended the Credit Agreement to, among other things, extend the maturity date under the Credit Agreement from March 27, 2023 to March 27, 2024. We have the option, subject to certain conditions, to exercise two one-year extensions of the maturity date.

Loans under the Credit Agreement bear interest by reference, at our election, to the LIBOR rate or base rate. The applicable margin on LIBOR rate loans varies from 1.00% to 2.00% and the applicable margin on base rate loans varies from 0.00% to 1.00%, in each case determined based upon our credit rating. 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 varies from 0.10% to 0.30% based on our credit rating.

None of our subsidiaries are currently required to be a guarantor under the Credit Agreement. However, if any subsidiary guarantees or incurs debt in excess of the Priority Debt Basket (as defined in the Credit Agreement), such subsidiary is required to become a guarantor under the Credit Agreement.

The Credit Agreement contains representations, warranties, affirmative and negative covenants and events of default and associated remedies that we believe are customary for agreements of this nature, including certain restrictions on our ability and each of our subsidiaries to incur debt and grant liens. If our credit rating is below investment grade, we will become subject to a restricted payment covenant, which would require us to have a Pro Forma Debt Service Coverage Ratio (as defined in the Credit Agreement) greater than or equal to 1.50 to 1.00 immediately before and immediately after making any restricted payment. The Credit Agreement also requires that our total debt to capitalization ratio, expressed as a percentage, not exceed 50%. The Credit Agreement generally defines the total 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 end of the most recently ended fiscal quarter.

As of December 31, 2019, we had no borrowings outstanding under our revolving credit facility. We had $81,000 in letters of credit outstanding under our revolving credit facility at December 31, 2019 and, as a result, had available borrowing capacity of approximately $600 million at that date.

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, 2019, we had $63.3 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, 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. None of our subsidiaries are currently required to guarantee payment under the Credit Agreement.

Series A Senior Notes and Series B Senior Notes — On October 5, 2010, we completed the issuance and sale of $300 million in aggregate principal amount of our Series A Notes in a private placement. The Series A Notes bore interest at a rate of 4.97% per annum. On September 25, 2019, we fully prepaid the Series A Notes. The total amount of the prepayment, including the applicable "make-whole" premium, was approximately $308 million, which represents 100% of the principal and the "make-whole" premium to the prepayment date.

On June 14, 2012, we completed the issuance and sale of $300 million in aggregate principal amount of our Series B Notes in a private placement. The Series B Notes bore interest at a rate of 4.27% per annum. On December 16, 2019, we fully prepaid the Series B Notes. The total amount of the prepayment, including the applicable "make-whole" premium, was approximately $315 million, which represents 100% of the principal and the "make-whole" premium to the prepayment date.

As a result of the prepayments, we also recorded a $24.0 million loss on early debt extinguishment in 2019, which was included in "Interest expense, net of amount capitalized" in the consolidated statements of operations.

2028 Senior Notes and 2029 Senior Notes — On January 19, 2018, we completed an offering of $525 million in aggregate principal amount of our 2028 Notes. 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. On November 15, 2019, we completed an offering of $350 million in aggregate principal amount of our 2029 Notes. The net proceeds before offering expenses were approximately $347 million, of which we used $315 million to repay in full our Series B Notes, and the remainder to repay a portion of the borrowings under the Term Loan Agreement.

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.

We pay interest on the 2029 Notes on May 15 and November 15 of each year. The 2029 Notes will mature on November 15, 2029. The 2029 Notes bear interest at a rate of 5.15% per annum.

The 2028 Notes and 2029 Notes (together, the "Senior Notes") are 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 Senior 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 Senior Notes will be structurally subordinated to the liabilities (including trade payables) of our subsidiaries that do not guarantee the Senior Notes. None of our subsidiaries are currently required to be a guarantor under the Senior Notes. If our subsidiaries guarantee the Senior Notes in the future, such guarantees (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.

We, at our option, may redeem the Senior Notes in whole or in part, at any time or from time to time at a redemption price equal to 100% of the principal amount of such Senior Notes to be redeemed, plus accrued and unpaid interest, if any, on those Senior Notes to the redemption date, plus a "make-whole" premium. Additionally, commencing on November 1, 2027, in the case of the 2028 Notes, and on August 15, 2029, in the case of the 2029 Notes, we, at our option, may redeem the respective Senior Notes in whole or in part, at a redemption price equal to 100% of the principal amount of the Senior Notes to be redeemed, plus accrued and unpaid interest, if any, on those Senior Notes to the redemption date.

The indentures pursuant to which the Senior Notes were issued include 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 indentures.

Upon the occurrence of a change of control, as defined in the indentures, each holder of the Senior Notes may require us to purchase all or a portion of such holder's Senior 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 indentures also provide 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 Senior Notes to become or to be declared due and payable.

Commitments — As of December 31, 2019, we maintained letters of credit in the aggregate amount of $63.4 million primarily 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, 2019, no amounts had been drawn under the letters of credit.

As of December 31, 2019, we had commitments to purchase major equipment and make investments totaling approximately $51 million for our drilling, pressure pumping, directional drilling and oilfield rentals businesses.

Our pressure pumping business has entered into agreements to purchase minimum quantities of proppants and chemicals from certain vendors. The agreements expire in years 2020 through 2023. As of December 31, 2019, the remaining obligation under these agreements was approximately $37.8 million, of which approximately $15.8 million relates to purchases required during 2020. In the event 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, 2019 (in thousands):

	Payments due by period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
2029 Notes (1)	$ 350,000	$ —	$ —	$ —	$ 350,000
Interest on 2029 Notes (2)	180,250	18,025	36,050	36,050	90,125
2019 Term Loan (3)	100,000	—	100,000	—	—
Interest on 2019 Term Loan (4)	7,193	2,917	4,276	—	—
2028 Notes (5)	525,000	—	—	—	525,000
Interest on 2028 Notes (6)	176,269	20,738	41,475	41,475	72,581
Leases (7)	40,809	11,212	14,704	7,010	7,883
Equipment purchases (8)	50,768	50,768	—	—	—
Inventory purchases (9)	37,773	15,805	19,693	2,275	—
Total	$1,468,062	$119,465	$216,198	$86,810	$1,045,589

(1) Principal repayment of the 2029 Notes is required at maturity on November 15, 2029.

(2) Interest to be paid on the 2029 Notes using 5.15% coupon rate.

(3) Principal repayment of the 2019 Term Loan is required at maturity on June 10, 2022.

(4) Interest to be paid on 2019 Term Loan using 2.917% rate in effect as of December 31, 2019.

(5) Principal repayment of the 2028 Notes is required at maturity on February 1, 2028.

(6) Interest to be paid on the 2028 Notes using 3.95% coupon rate.

(7) See Note 12 of Notes to Consolidated Financial Statements.

(8) Represents commitments to purchase major equipment to be delivered in 2020 based on expected delivery dates.

(9) Represents commitments to purchase proppants and chemicals for our pressure pumping business.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements at December 31, 2019.

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,		
	2019	2018	2017
	(Dollars in thousands)		
Net income (loss)	$ (425,703)	$(321,421)	$ 5,910
Income tax benefit	(104,675)	(45,987)	(333,711)
Net interest expense	69,191	45,981	35,606
Depreciation, depletion, amortization and impairment	1,003,873	916,318	783,341
Impairment of goodwill	17,800	211,129	—
Adjusted EBITDA	$ 560,486	$ 806,020	$ 491,146

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 and the use of estimates.

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 inactive rigs to working condition and the expected demand for drilling services by rig type. 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 are retired. In 2019, we identified 36 legacy non-APEX® rigs and related equipment that would be retired. Based on the strong customer preference across the industry for super-spec drilling rigs, we believe the 36 rigs that were retired have limited commercial opportunity. We recorded a $173 million charge related to this retirement. In 2018, we identified 42 legacy non-APEX® rigs and related equipment that would be retired. Based on the strong customer preference across the industry for super-spec drilling rigs, we believe the 42 rigs that were retired had limited commercial opportunity. We recorded a $48.4 million charge related to this retirement. In 2017, we recorded a 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.

We also periodically evaluate our pressure pumping assets for marketability based on the condition of inactive equipment, expenditures that would be necessary to bring the equipment to working condition and the expected demand. The components of equipment that will no longer be marketed are evaluated, and those components with continuing utility will be used as parts to support active equipment. The remaining components of this equipment are retired. In 2019, we recorded a charge of $20.5 million for the write-down of pressure pumping equipment compared to a $17.4 million write-down of pressure pumping equipment in 2018. There was no similar charge in 2017.

We also periodically evaluate our directional drilling assets. During 2019, we recorded a charge of $8.4 million for the write-down of directional drilling equipment. There were no similar charges in 2018 or 2017.

We review our long-lived assets, including property and equipment, for impairment whenever events or changes in circumstances indicate that the 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. 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 our 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.

2019 Triggering Event Assessment

Due to the decline in the market price of our common stock and recent commodity prices, our results of operations for the quarter ended September 30, 2019 and our expectations of operating results in future periods, we lowered our expectations with respect to future activity levels in certain of our operating segments. We deemed it necessary to assess the recoverability of our contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups as of September 30, 2019. We performed an analysis as required by ASC 360-10-35 to assess the recoverability of the asset groups within our contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments as of September 30, 2019. With respect to these asset groups, 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 asset groups, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the asset groups within the contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments by approximately 35%, 54%, 23% and 7%, respectively.

For the assessment performed in 2019, the expected cash flows for our asset groups included revenue growth rates, operating expense growth rates, and terminal growth rates. Also, the expected cash flows for the contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups were based on the assumption that activity levels in all four segments would generally be lower than levels experienced in 2019 and would begin to recover in late 2020 or 2021 in response to improved oil prices. While we believe these assumptions with respect to future oil pricing are reasonable, actual future prices and activity levels may vary significantly from the ones that were assumed. The timeframe over which oil prices and activity levels may recover is highly uncertain. Potential events that could affect our assumptions regarding future prices and the timeframe for a recovery are affected by factors such as those described in "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."

All of these factors are beyond our control. If the lower oil price environment experienced in 2019 were to last into late 2021 and beyond, our actual cash flows would likely be less than the expected cash flows used in these assessments and could result in impairment charges in the future, and such impairment could be material.

We concluded that no triggering events occurred during the quarter ended December 31, 2019 with respect to our asset groups based on our recent results of operations, management's expectations of operating results in future periods and the prevailing commodity prices at the time.

Prior Year Triggering Event Assessment

Due to the decline in the market price of our common stock and the deterioration of crude oil prices in the fourth quarter of 2018, we lowered our expectations with respect to future activity levels in certain of our operating segments. We deemed it necessary to assess the recoverability of our contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups. We performed an analysis as required by ASC 360-10-35 to assess the recoverability of the asset groups within our contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments as of December 31, 2018. With respect to these asset groups, 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 asset groups, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the asset groups within the contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments by approximately 38%, 58%, 9% and 23%, respectively.

For the assessment performed in 2018, the expected cash flows for our asset groups included revenue growth rates, operating expense growth rates, and terminal growth rates. Also, the expected cash flows for the contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups were based on the assumption that activity levels in all four segments would generally be lower than levels experienced in the fourth quarter of 2018, and would begin to recover in late 2019 and continue into 2020 in response to improved oil prices and activity levels.

We concluded that no triggering events occurred during the year ended December 31, 2017 with respect to our asset groups based on our results of operations for the year ended December 31, 2017, our expectations of operating results in future periods and the prevailing commodity prices at the time.

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 impairment testing purposes, goodwill is evaluated at the reporting unit level. Our reporting units for impairment testing are 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.

Due to the decline in the market price of our common stock and recent commodity prices, our results of operations for the quarter ended September 30, 2019 and our expectations of operating results in future periods, we lowered our expectations with respect to future activity levels in certain of our operating segments. We performed a quantitative impairment assessment of our goodwill as of September 30, 2019. In completing the assessment, the fair value of each reporting unit was estimated using the income approach. 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 assumptions included discount rates, revenue growth rates, operating expense growth rates, and terminal growth rates.

Based on the results of the goodwill impairment test as of September 30, 2019, the fair value of the contract drilling reporting unit exceeded its carrying value by approximately 13% and we concluded that no impairment was indicated in our contract drilling reporting unit; however, impairment was indicated in our oilfield rentals and electrical controls and automation reporting units included in the other operations segment. We recognized an impairment charge of $17.8 million in 2019 associated with the impairment of all of the goodwill in our oilfield rentals and electrical controls and automation reporting units.

The timeframe over which oil prices and activity levels may recover is highly uncertain. If the lower oil price environment experienced in 2019 were to last into late 2021 and beyond, our actual cash flows would likely be less than the expected cash flows used in these assessments and could result in additional goodwill impairment charges in the future and such impairment could be material.

Due to the decline in the market price of our common stock and the deterioration of crude oil prices in the fourth quarter of 2018, we lowered our expectations with respect to future activity levels in certain of our operating segments. We performed a quantitative impairment assessment of our goodwill as of December 31, 2018. In completing the assessment, the fair value of each reporting unit was estimated using the income approach. 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 assumptions included discount rates, revenue growth rates, operating expense growth rates, and terminal growth rates.

Based on the results of the goodwill impairment assessment as of December 31, 2018, the fair value of the contract drilling and oilfield rentals reporting units exceeded their carrying values by approximately 16% and 14%, respectively, and we concluded that no impairment was indicated in our contract drilling and oilfield rentals reporting units; however, impairment was indicated in our pressure pumping and directional drilling reporting units. We recognized an impairment charge of $211 million associated with the impairment of all of the goodwill in our pressure pumping and directional drilling reporting units.

In connection with our annual goodwill impairment assessment as of December 31, 2019 and 2017, 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 2019 and 2017 operating results and forecasted operating results for the respective succeeding year. We also considered our overall market capitalization at December 31, 2019 and 2017.

Revenue recognition — On January 1, 2018, we adopted the new revenue guidance under Topic 606, *Revenue from Contracts with Customers*, using the modified retrospective method for contracts that were not complete at December 31, 2017. The adoption of the new accounting standard did not have a material impact on our consolidated financial statements, and a cumulative adjustment was not recognized. Revenues for reporting periods beginning after January 1, 2018 are presented under Topic 606, while revenues prior to January 1, 2018 continue to be reported under previous revenue recognition requirements of Topic 605.

Leases — On January 1, 2019, we adopted the new lease guidance under Topic 842, *Leases*, using the modified retrospective approach to each lease that existed at the date of initial application as well as leases entered into after that date. We have elected to report all leases at the beginning of the period of adoption and not restate our comparative periods. This standard does not apply to leases to explore for or use minerals, oil, natural gas and similar non-regenerative resources, including the intangible right to explore for those natural resources and rights to use the land in which those natural resources are contained. See Note 12 for Notes to consolidated financial statements for additional information.

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. Oil prices reached a twelve-year low of $26.19 per barrel in February 2016. Oil prices have recovered from the lows experienced in the first quarter of 2016, and reached a high of $77.41 in June 2018. Oil prices remain volatile, as the closing price of oil began the year at a low of $46.31 per barrel on January 2, 2019, before increasing by 43% over the course of four months to reach a high of $66.24 per barrel in late April 2019. Since May 2019, oil prices have generally ranged between $50 and $60 per barrel. Oil prices averaged $56.94 per barrel in the fourth quarter of 2019 and closed at $50.06 per barrel on February 3, 2020. U.S. rig counts increased in response to improved oil prices in early 2018. Despite oil prices in the $50s, drilling and pressure pumping activity declined in 2019, particularly toward the end of the year, largely as a result of reduced customer spending.

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, as well as our customers' ability to access sources of capital to fund their operating and capital expenditures. A decline in demand for oil and natural gas, prolonged low oil or natural gas prices, expectations of decreases in oil and natural gas prices or a reduction in the ability of our customers to access capital, 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 historically moderate or 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, 2019. 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***

As of December 31, 2019, we had exposure to interest rate market risk associated with our borrowings under the Term Loan Agreement, and we would have had exposure to interest rate market risk associated with any borrowings that we had under the Credit Agreement and amounts owed under the Reimbursement Agreement.

Loans under the Term Loan Agreement bear interest by reference, at our election, to the LIBOR rate or base rate. The applicable margin on LIBOR rate loans varies from 1.00% to 1.375%, and the applicable margin on base rate loans varies from 0.00% to 0.375%, in each case determined based upon our credit rating. As of December 31, 2019, the applicable margin on LIBOR rate loans and base rate loans was 1.125% and 0.125%, respectively. As of December 31, 2019, we had $100 million in borrowings outstanding under the Term Loan Agreement at a weighted average interest rate of 2.917%. A one percent increase in the interest rate on the borrowings outstanding under the Term Loan Agreement as of December 31, 2019 would increase our annual cash interest expense by $1.0 million.

Loans under the Credit Agreement bear interest by reference, at our election, to the LIBOR rate or base rate. The applicable margin on LIBOR rate loans varies from 1.00% to 2.00% and the applicable margin on base rate loans varies from 0.00% to 1.00%, in each case determined based on our credit rating. As of December 31, 2019, the applicable margin on LIBOR rate loans was 1.50% and the applicable margin on base rate loans was 0.50%. As of December 31, 2019, we had no borrowings outstanding under our revolving credit facility. The interest rate on 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 Scotiabank on demand for any amounts that Scotiabank has disbursed under any letters of credit. We are obligated to pay Scotiabank 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, 2019, no amounts had been disbursed under any letters of credit.

We conduct a portion of our business in Canadian dollars. 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 financial condition or results of operations.

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, 2019, 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, 2019, 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, 2019.

The effectiveness of our internal control over financial reporting as of December 31, 2019 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	Certificate of Amendment to Restated Certificate of Incorporation, as amended (filed July 30, 2018 as Exhibit 3.4 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2018 and incorporated herein by reference).
3.5	Fourth Amended and Restated Bylaws (filed February 12, 2019 as Exhibit 3.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
4.1	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934.+
4.2	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).
4.3	Registration Rights Agreement, dated as of October 11, 2017, between Patterson-UTI Energy, Inc. and the sellers party thereto. (filed February 20, 2018 as Exhibit 4.2 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2017 and incorporated herein by reference).
4.4	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).
4.5	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).

4.6	Form of 3.95% Senior Note due 2028 (included in Exhibit 4.5 above).
4.7	Base Indenture, dated November 15, 2019, between Patterson-UTI Energy, Inc. and U.S. Bank National Association, as trustee (filed November 15, 2019 as Exhibit 4.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
4.8	First Supplemental Indenture, dated November 15, 2019, between Patterson-UTI Energy, Inc. and U.S. Bank National Association, as trustee (filed November 15, 2019 as Exhibit 4.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).
4.9	Form of 5.15% Senior Note due 2029 (included in Exhibit 4.8 above).
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 by 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).*
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	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).*
10.8	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. 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).*
10.10	Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan, as amended and restated and further amended effective June 6, 2019 (filed June 6, 2019 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 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).*
10.12	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).*
10.13	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).*

10.14	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).*
10.15	Form of Non-Employee Director Restricted Stock Unit Award Agreement (filed February 20, 2018 as Exhibit 10.19 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2017 and incorporated herein by reference).*
10.16	Form of Executive Officer Share-Settled Performance Share Award Agreement (filed February 13, 2019 as Exhibit 10.15 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2018 and incorporated herein by reference).*
10.17	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).*
10.18	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).*
10.19	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).*
10.20	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).*
10.21	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).*
10.22	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, Seth D. Wexler, William Andrew Hendricks, Jr., Michael W. Conlon, Tiffany J. Thom, C. Andrew Smith and Janeen S. Judah (filed April 28, 2004 as Exhibit 10.11 to the Company's Annual Report on Form 10-K, as amended, for the year ended December 31, 2003 and incorporated herein by reference).*
10.23	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).*
10.24	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).*
10.25	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).*
10.26	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).*

10.27	Amended and Restated Credit Agreement dated March 27, 2018 among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, letter of credit issuer, swing line lender and lender and each of the other letter of credit issuers and lenders party thereto (filed March 27, 2018 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.28	Amendment No. 1 to Amended and Restated Credit Agreement, dated March 26, 2019, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, letter of credit issuer, swing line lender and lender and each of the other letter of credit issuers and lenders party thereto (filed March 26, 2019 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.29	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).
10.30	Term Loan Agreement, dated August 22, 2019, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent and lender and the other lender party thereto (filed August 23, 2019 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.INS	Inline XBRL Instance Document—the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.+
101.SCH	Inline XBRL Taxonomy Extension Schema Document+
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document+
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document+
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document+
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document+
104	Cover Page Interactive Data File (formatted as inline XBRL with applicable taxonomy extension information contained in Exhibits 101).

* 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 (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of operations, of comprehensive income (loss), of changes in stockholders' equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes and schedule of valuation and qualifying accounts for each of the three years in the period ended December 31, 2019 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, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, 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 accounts for leases in 2019.

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.

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.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Goodwill Impairment Test—Contract Drilling Reporting Unit as of September 30, 2019

As described in Note 6 to the consolidated financial statements, the Company's consolidated goodwill balance was $395 million, all of which relates to the contract drilling reporting unit as of December 31, 2019. Management evaluates goodwill 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 impairment testing purposes, goodwill is evaluated at the reporting unit level. The Company's reporting units for impairment testing are its operating segments. Management 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. 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. As a result of triggering events for the quarter ended September 30, 2019, management performed a quantitative impairment assessment of its goodwill as of September 30, 2019. In completing the assessment, the fair value of each reporting unit was estimated using the income approach. The assumptions used in the income approach included discount rate, revenue growth rates, operating expense growth rates, and terminal growth rate.

The principal considerations for our determination that performing procedures relating to the Goodwill Impairment Test—Contract Drilling Reporting Unit as of September 30, 2019 is a critical audit matter are there was significant judgment by management when estimating the fair value of the reporting unit. This in turn led to a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating audit evidence obtained related to the significant assumptions in management's cash flow projections, including discount rate, revenue growth rates, operating expense growth rates, and terminal growth rate. In addition, the audit effort involved the use of professionals with specialized skill and knowledge to assist in performing these procedures and evaluating the audit evidence obtained.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's goodwill impairment test, including controls over the estimation of the fair value of the Company's reporting unit. These procedures also included, among others, evaluating the appropriateness of the method; testing the completeness, accuracy, and relevance of the underlying data used in the estimate; and evaluating the reasonableness of significant assumptions used by management in developing the fair value estimates including discount rate, revenue growth rates, operating expense growth rates, and terminal growth rate. Evaluating management's significant assumptions related to the revenue growth rates and operating expense growth rates, involved evaluating whether the significant assumptions used by management were reasonable considering the current and past performance of the reporting unit and considered whether they were consistent with evidence obtained in other areas of the audit. Professionals with specialized skill and knowledge were used to assist in the evaluation of the Company's method and certain assumptions, including the discount rate and terminal growth rate.

Long-lived Assets and Intangible Assets Recoverability Test—Asset Groupings in the Contract Drilling and Pressure Pumping Operating Segments as of September 30, 2019

As described in Notes 5 and 6 to the consolidated financial statements, the Company's consolidated net property and equipment and consolidated intangible assets balance were $3,307 million and $49 million, respectively, most of which relates to the Contract Drilling and Pressure Pumping asset groupings as of December 31, 2019. Management reviews its long-lived assets, including property and equipment and intangibles, for impairment whenever events or changes in circumstances indicate that their carrying amounts of certain asset groupings may not be recovered over their estimated remaining useful lives. As a result of triggering events for the quarter ended September 30, 2019, management deemed it necessary to assess the recoverability of its contract drilling and pressure pumping asset groups as of September 30, 2019. Management performed an analysis to assess the recoverability of the asset groups within its contract drilling and pressure pumping operating segments as of September 30, 2019. With respect to these asset groups, future cash flows were estimated over the expected remaining life of the assets, and management determined that, on an undiscounted basis, expected cash flows exceeded the carrying value of the asset groups, and no impairment was indicated. For the assessment performed in 2019, the expected cash flows for the Company's asset groups included revenue growth rates, operating expenses growth rates, and terminal growth rate.

The principal considerations for our determination that performing procedures relating to the Long-lived Assets and Intangible Assets Recoverability Test—Asset Groupings in the Contract Drilling and Pressure Pumping Operating Segments as of September 30, 2019 is a critical audit matter are there was significant judgment by management when estimating the future undiscounted cash flows of the asset groupings. This in turn led to a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating audit evidence obtained related to the significant assumptions in management's cash flow projections, including revenue growth rates, operating expense growth rates, and terminal growth rate.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's long-lived assets and intangible assets recoverability test, including controls over the estimation of the undiscounted future cash flows of the Company's asset groupings. These procedures also included, among others, evaluating the appropriateness of the method; testing the completeness, accuracy, and relevance of the underlying data used in the cash flows; and evaluating the reasonableness of significant assumptions used by management in developing their estimate of undiscounted future cash flows including revenue growth rates, operating expense growth rates and terminal growth rate. Evaluating management's significant assumptions related to the revenue growth rates, operating expense growth rates and terminal growth rate, involved evaluating whether the significant assumptions used by management were reasonable considering the current and past performance of the asset groupings and considered whether they were consistent with evidence obtained in other areas of the audit.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 13, 2020

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2019	December 31, 2018
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 174,185	$ 245,029
Accounts receivable, net of allowance for doubtful accounts of $6,516 and $2,312 at December 31, 2019 and 2018, respectively	339,699	558,817
Federal and state income taxes receivable	6,397	4,110
Inventory	36,357	65,579
Other	75,177	76,662
Total current assets	631,815	950,197
Property and equipment, net	3,306,677	4,002,549
Right of use asset	31,275	—
Goodwill and intangible assets	444,004	477,640
Deposits on equipment purchases	8,066	12,040
Other	17,778	27,440
Total assets	$ 4,439,615	$ 5,469,866
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 170,475	$ 288,962
Federal and state income taxes payable	342	1,408
Accrued liabilities	219,850	235,946
Lease liability	9,935	—
Total current liabilities	400,602	526,316
Long-term lease liability	26,644	—
Long-term debt, net of debt discount and issuance costs of $8,460 and $5,795 at December 31, 2019 and 2018, respectively	966,540	1,119,205
Deferred tax liabilities, net	202,959	306,161
Other	9,250	12,761
Total liabilities	1,605,995	1,964,443
Commitments and contingencies (see Note 9)		
Stockholders' equity:		
Preferred stock, par value $.01; authorized 1,000,000 shares, no shares issued	—	—
Common stock, par value $.01; authorized 400,000,000 shares with 269,372,257 and 267,315,526 issued and 192,035,870 and 213,614,430 outstanding at December 31, 2019 and 2018, respectively	2,694	2,673
Additional paid-in capital	2,875,680	2,827,154
Retained earnings	1,294,902	1,753,557
Accumulated other comprehensive income	5,478	2,487
Treasury stock, at cost, 77,336,387 shares and 53,701,096 shares at December 31, 2019 and 2018, respectively	(1,345,134)	(1,080,448)
Total stockholders' equity	2,833,620	3,505,423
Total liabilities and stockholders' equity	$ 4,439,615	$ 5,469,866

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,		
	2019	2018	2017
	(In thousands, except per share data)		
Operating revenues:			
Contract drilling	$1,308,350	$1,430,492	$1,040,033
Pressure pumping	868,694	1,573,396	1,200,311
Directional drilling	188,786	209,275	45,580
Other	104,855	113,834	70,760
Total operating revenues	2,470,685	3,326,997	2,356,684
Operating costs and expenses:			
Contract drilling	785,355	885,704	667,105
Pressure pumping	724,788	1,263,850	966,835
Directional drilling	178,645	175,829	32,172
Other	84,909	77,104	51,428
Depreciation, depletion, amortization and impairment	1,003,873	916,318	783,341
Impairment of goodwill	17,800	211,129	—
Selling, general and administrative	133,513	134,071	105,847
Provision for bad debts	5,683	—	—
Merger and integration expenses	—	2,738	74,451
Other operating income, net	(2,305)	(17,569)	(31,957)
Total operating costs and expenses	2,932,261	3,649,174	2,649,222
Operating loss	(461,576)	(322,177)	(292,538)
Other income (expense):			
Interest income	6,013	5,597	1,866
Interest expense, net of amount capitalized	(75,204)	(51,578)	(37,472)
Other	389	750	343
Total other expense	(68,802)	(45,231)	(35,263)
Loss before income taxes	(530,378)	(367,408)	(327,801)
Income tax benefit	(104,675)	(45,987)	(333,711)
Net income (loss)	$ (425,703)	$ (321,421)	$ 5,910
Net income (loss) per common share:			
Basic	$ (2.10)	$ (1.47)	$ 0.03
Diluted	$ (2.10)	$ (1.47)	$ 0.03
Weighted average number of common shares outstanding:			
Basic	203,039	218,643	198,447
Diluted	203,039	218,643	199,882

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,		
	2019	2018	2017
	(In thousands)		
Net income (loss)	$(425,703)	$(321,421)	$ 5,910
Other comprehensive income (loss), net of taxes of $0 for 2019, $0 for 2018 and $0 for 2017:			
Foreign currency translation adjustment	2,991	(4,335)	7,956
Total comprehensive income (loss)	$(422,712)	$(325,756)	$13,866

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		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total
	Number of Shares	Amount					
	(In thousands)						
Balance, December 31, 2016	191,526	$1,915	$1,042,696	$2,116,341	$(1,134)	$ (911,094)	$2,248,724
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
Net loss	—	—	—	(321,421)	—	—	(321,421)
Foreign currency translation adjustment	—	—	—	—	(4,335)	—	(4,335)
Restricted stock issued for acquisition	192	2	2,930	—	—	—	2,932
Issuance of restricted stock	381	4	(4)	—	—	—	—
Vesting of restricted stock units	452	5	(5)	—	—	—	—
Forfeitures of restricted stock	(8)	—	—	—	—	—	—
Exercise of stock options	40	—	485	—	—	—	485
Stock-based compensation	—	—	37,925	—	—	—	37,925
Payment of cash dividends	—	—	—	(30,589)	—	—	(30,589)
Dividend equivalents	—	—	—	(330)	—	—	(330)
Purchase of treasury stock	—	—	—	—	—	(161,737)	(161,737)
Balance, December 31, 2018	267,316	$2,673	$2,827,154	$1,753,557	$ 2,487	$(1,080,448)	$3,505,423
Net loss	—	—	—	(425,703)	—	—	(425,703)
Foreign currency translation adjustment	—	—	—	—	2,991	—	2,991
Issuance of restricted stock	185	2	(2)	—	—	—	—
Vesting of restricted stock units	1,173	12	(12)	—	—	—	—
Forfeitures of restricted stock	(2)	—	—	—	—	—	—
Exercise of stock options	700	7	9,212	—	—	—	9,219
Stock-based compensation	—	—	39,328	—	—	—	39,328
Payment of cash dividends	—	—	—	(32,428)	—	—	(32,428)
Dividend equivalents	—	—	—	(524)	—	—	(524)
Purchase of treasury stock	—	—	—	—	—	(264,686)	(264,686)
Balance, December 31, 2019	269,372	$2,694	$2,875,680	$1,294,902	$ 5,478	$(1,345,134)	$2,833,620

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,		
	2019	2018	2017
	(In thousands)		
Cash flows from operating activities:			
Net income (loss)	$ (425,703)	$(321,421)	$ 5,910
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and impairment	1,003,873	916,318	783,341
Impairment of goodwill	17,800	211,129	—
Dry holes and abandonments	109	915	1,929
Deferred income tax benefit	(103,202)	(41,185)	(330,346)
Stock-based compensation expense	39,328	37,925	44,483
Net gain on asset disposals	(13,904)	(28,958)	(33,510)
Write-down of capacity reservation contract	12,673	—	—
Provision for bad debts	5,683	—	—
Loss on early debt extinguishment	24,023	—	—
Amortization of debt discount and issuance costs	937	830	346
Changes in operating assets and liabilities:			
Accounts receivable	213,588	23,515	(239,482)
Income taxes receivable/payable	(3,353)	(1,555)	990
Inventory and other assets	29,394	(1,470)	(23,449)
Accounts payable	(77,686)	(69,453)	104,072
Accrued expenses	(18,218)	4,136	(14,190)
Other liabilities	(9,139)	(56)	617
Net cash provided by operating activities	696,203	730,670	300,711
Cash flows from investing activities:			
Acquisitions, net of cash acquired	(13)	(14,211)	(501,954)
Purchases of property and equipment	(347,512)	(641,458)	(567,087)
Proceeds from disposal of assets and insurance claims	45,761	47,357	60,945
Collection of note receivable	—	23,760	—
Other investments	—	—	(2,520)
Net cash used in investing activities	(301,764)	(584,552)	(1,010,616)
Cash flows from financing activities:			
Proceeds from equity offering	—	—	471,570
Purchases of treasury stock	(255,467)	(161,737)	(6,809)
Dividends paid	(32,428)	(30,589)	(16,315)
Proceeds from long-term debt	496,969	521,194	—
Repayment of long-term debt	(673,443)	—	—
Proceeds from borrowings under revolving credit facility	—	79,000	599,000
Repayment of borrowings under revolving credit facility	—	(347,000)	(331,000)
Debt issuance costs	(852)	(4,489)	—
Proceeds from exercise of stock options	—	485	123
Net cash provided by (used in) financing activities	(465,221)	56,864	716,569
Effect of foreign exchange rate changes on cash	(62)	(781)	1,012
Net increase (decrease) in cash and cash equivalents	(70,844)	202,201	7,676
Cash and cash equivalents at beginning of year	245,029	42,828	35,152
Cash and cash equivalents at end of year	$ 174,185	$ 245,029	$ 42,828
Supplemental disclosure of cash flow information:			
Net cash (paid) received during the year for:			
Interest, net of capitalized interest of $732 in 2019, $1,435 in 2018 and $1,175 in 2017	$ (76,870)	$ (41,184)	$ (34,953)
Income taxes	(1,452)	3,172	3,947
Non-cash investing and financing activities:			
Receivable from property and equipment insurance	$ —	$ 15,000	$ —
Net increase (decrease) in payables for purchases of property and equipment	(40,857)	36,241	17,228
Issuance of common stock for business acquisitions	—	2,932	1,226,890
Net decrease (increase) in deposits on equipment purchases	3,974	4,311	(301)
Cashless exercise of stock options	9,219	—	—

The accompanying notes are an integral part of these 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"), is 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. The Company's contract drilling business operates in the continental United States and western Canada, and the Company is pursuing contract drilling opportunities outside of North America. The Company's pressure pumping business operates primarily in Texas and the Mid-Continent and Appalachian regions. The Company also provides a comprehensive suite of directional drilling services in most major producing onshore oil and gas basins in the United States, and the Company provides services that improve the statistical accuracy of horizontal wellbore placement. The Company has other operations through which the Company provides oilfield rental tools in select markets in the United States. The Company also services equipment for drilling contractors, and provides electrical controls and automation to the energy, marine and mining industries, 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. As used in these notes, "the Company" refers collectively to Patterson-UTI Energy, Inc. and its consolidated subsidiaries. Patterson-UTI Energy, Inc. conducts its business operations through its wholly-owned subsidiaries and has no employees or independent operations.

The U.S. dollar is the functional currency for all of the Company's operations except for its Canadian operations, 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.

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 the Company's contract drilling, pressure pumping, directional drilling, oilfield rentals, equipment servicing and electrical control and automation activities are recognized as services are performed. All of the wells the Company drilled in 2019, 2018 and 2017 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.

On January 1, 2018, the Company adopted the new revenue guidance under Topic 606, *Revenue from Contracts with Customers*, using the modified retrospective method for contracts that were not complete at December 31, 2017. The adoption of the new accounting standard did not have a material impact on the Company's consolidated financial statements, and a cumulative adjustment was not recognized. See Note 3 for additional information.

Leases — The Company enters operating leases for operating locations, corporate offices and certain operating equipment. As of December 31, 2019, the Company does not have any finance leases.

On January 1, 2019, the Company adopted the new lease guidance under Topic 842, *Leases*, using the modified retrospective approach to each lease that existed at the date of initial application as well as leases entered into after that date. The Company has elected to report all leases at the beginning of the period of adoption and not restate its comparative periods. This standard does not apply to leases to explore for or use minerals, oil, natural gas and similar non-regenerative resources, including the intangible right to explore for those natural resources and rights to use the land in which those natural resources are contained. See Note 12 for additional information.

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 uncollectible, 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 equipment servicing 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 $39.0 million and $35.6 million at December 31, 2019 and 2018, 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. Impairment expense related to oil and natural gas properties of approximately $2.2 million, $1.0 million and $4.3 million was recorded for the years ended December 31, 2019, 2018 and 2017, respectively.

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.

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.

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 11).

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 Adopted Accounting Standards — In May 2014, the Financial Accounting Standards Board ("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 Company adopted this new revenue guidance effective January 1, 2018, utilizing the modified retrospective method, and expanded its consolidated financial statement disclosures in order to comply with the update (See Note 3). 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 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 Company adopted this new leasing guidance effective January 1, 2019 and expanded its consolidated financial statement disclosures in order to comply with the update (See Note 12). The adoption of this standard resulted in the recording of operating lease right of use assets of approximately $31.0 million and operating lease liabilities of approximately $35.8 million as of January 1, 2019.

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. The Company adopted this guidance effective January 1, 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 issued in the case of stock option exercises.

In August 2016, the FASB issued an accounting standards update 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 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.

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.

In March 2018, the FASB issued an accounting standards update to update the income tax accounting in U.S. GAAP to reflect the SEC interpretive guidance released on December 22, 2017, when significant U.S. tax law changes were enacted with the enactment of "H.R.1," also known as the "Tax Cuts and Jobs Act" ("U.S. Tax Reform"). The adoption of this update in March 2018 did not have a material impact on the Company's consolidated financial statements, as the Company was already following the SEC guidance (See Note 13).

Recently Issued Accounting Standards — In June 2016, the FASB issued an accounting standards update on measurement of credit losses on financial instruments. This update improves financial reporting by requiring earlier recognition of credit losses on financing receivables and other financial assets in scope by using the Current Expected Credit Losses model (CECL). The CECL model utilizes a lifetime expected credit loss measurement objective for the recognition of credit losses on financial instruments at the time the asset is originated or acquired. This update will apply to receivables arising from revenue transactions such as contract assets and accounts receivables. This update is effective for interim and annual periods beginning after December 15, 2019, with early adoption permitted. The Company will adopt this new guidance on January 1, 2020 and does not expect this new guidance will have a material impact on its consolidated financial statements.

In August 2018, the FASB issued an accounting standards update to align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The capitalized implementation costs of a hosting arrangement that is a service contract will be expensed over the term of the hosting arrangement. The amendments in the update are effective for public business entities for fiscal years beginning after December 15, 2019, with early adoption permitted. The guidance allows adoption using a retrospective or prospective method. The Company will adopt this new guidance on January 1, 2020 prospectively with respect to all implementation costs incurred after the date of adoption.

In August 2018, the FASB issued an accounting standards update to eliminate certain disclosure requirements for fair value measurements for all entities, require public entities to disclose certain new information and modify certain disclosure requirements. The FASB developed the amendments to Topic 820 as part of its broader disclosure framework project, which aims to improve the effectiveness of disclosures in the notes to financial statements by focusing on requirements that clearly communicate the most important information to users of the financial statements. This update is effective for interim and annual periods beginning after December 15, 2019, with early adoption permitted. The Company will adopt this new guidance on January 1, 2020 and does not expect this new guidance will have a material impact on its consolidated financial statements.

In December 2019, the FASB issued an accounting standards update to simplify the accounting for income taxes. The amendments in the update are effective for public business entities for fiscal years beginning after December 15, 2020, with early adoption permitted. The Company plans to adopt this guidance on January 1, 2021 and is currently evaluating the impact of adoption on its consolidated financial statements.

During the third quarter of 2019, the Company identified and recorded out-of-period adjustments primarily related to the accounting for inventory in its directional drilling segment. The Company concluded that these adjustments were not material to the consolidated financial statements for any of the current or prior periods presented. The net adjustment is reflected as a $6.6 million increase to "Loss before income taxes" in the consolidated statements of operations for the year ended December 31, 2019.

2. Acquisitions

SSE

On April 20, 2017, pursuant to a merger agreement, a subsidiary of the Company was merged with and into Seventy Seven Energy, Inc ("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 fracturing equipment. The oilfield rentals business acquired through the SSE merger has a 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.

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 following table represents the final 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 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, access to new geographies, access to new product lines, increased scale of operations, supply chain and corporate efficiencies as well as infrastructure optimization. The acquired goodwill was attributable to three operating segments, with $309 million to contract drilling, $121 million to pressure pumping and $6.3 million to oilfield rentals. See Note 6 for additional information regarding goodwill.

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

	Fair Value	Weighted Average Useful Life
	(in thousands)	(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, LLC (f/k/a Multi-Shot, LLC) ("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 was 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, 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.

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 following table represents the final 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	44,099
Other long-term liabilities	327
Total liabilities assumed	44,426
Net identifiable assets acquired	167,590
Goodwill	89,685
Total net assets acquired	$257,275

The goodwill reflected above increased $1.0 million from the original preliminary purchase price allocation as a result of a measurement period adjustment that related to a valuation adjustment to accounts payable and accrued liabilities.

The acquired goodwill was 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, access to new product lines, favorable market trends underlying these new business lines, earnings and growth opportunities and future technology development possibilities. All of the goodwill acquired was attributable to the directional drilling operating segment. See Note 6 for additional information regarding goodwill.

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

	Fair Value	Weighted Average Useful Life
	(in thousands)	(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 the Company's 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 accounts for substantially all of the Company's directional drilling segment, as disclosed in Note 16. 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 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)

Current Power Solutions, Inc. (“Current Power”)

During October 2018, the Company acquired Current Power. Current Power is a provider of electrical controls and automation to the energy, marine and mining industries. This acquisition was not material to the Company’s consolidated financial statements.

Superior QC, LLC (“Superior QC”)

During February 2018, the Company acquired the business of Superior QC, including its assets and intellectual property. Superior QC is a provider of software and services used to improve the statistical accuracy of horizontal wellbore placement. Superior QC’s measurement-while-drilling (MWD) Survey FDIR (fault detection, isolation and recovery) service is a data analytics technology to analyze MWD survey data in real-time and more accurately identify the position of a well. This acquisition was not material to the Company’s consolidated financial statements.

3. Revenues

ASC Topic 606 Revenue from Contracts with Customers

On January 1, 2018, the Company adopted the new revenue guidance under Topic 606, *Revenue from Contracts with Customers*, using the modified retrospective method for contracts that were not complete at December 31, 2017. The adoption of the new accounting standard did not have a material impact on the Company’s consolidated financial statements, and a cumulative adjustment was not recognized. Revenues for reporting periods beginning after January 1, 2018 are presented under Topic 606, while revenues prior to January 1, 2018 continue to be reported under previous revenue recognition requirements of Topic 605.

The Company’s contracts with customers include both long-term and short-term contracts. Services that primarily generate revenue earned for the Company include the operating business segments of contract drilling, pressure pumping and directional drilling which comprise the Company’s reportable segments. The Company also derives revenues from its other operations, which include the Company’s operating business segments of oilfield rentals, equipment servicing, electrical controls and automation, and oil and natural gas working interests. For more information on the Company’s business segments, see Note 16.

Charges for services are considered a series of distinct services. Since each distinct service in a series would be satisfied over time if it were accounted for separately, and the entity would measure its progress towards satisfaction using the same measure of progress for each distinct service in the series, the Company is able to account for these integrated services as a single performance obligation that is satisfied over time.

The transaction price is the amount of consideration to which the Company expects to be entitled in exchange for transferring promised goods or services to a customer, based on terms of the Company’s contracts with its customers. The consideration promised in a contract with a customer may include fixed amounts and/or variable amounts. Payments received for services are considered variable consideration as the time in service will fluctuate as the services are provided. Topic 606 provides an allocation exception, which allows the Company to allocate variable consideration to one or more distinct services promised in a series of distinct services that form part of a single performance obligation as long as certain criteria are met. These criteria state that the variable payment must relate specifically to the entity’s efforts to satisfy the performance obligation or transfer the distinct good or service, and allocation of the variable consideration is consistent with the standards’ allocation objective. Since payments received for services meet both of these criteria requirements, the Company recognizes revenue when the service is performed.

An estimate of variable consideration should be constrained to the extent that it is not probable that a significant revenue reversal in the amount of cumulative revenue recognized will not occur when the uncertainty associated with the variable consideration is subsequently resolved. Payments received for other types of consideration are fully constrained as they are highly susceptible to factors outside the entity’s influence and therefore could be subject to a significant revenue reversal once resolved. As such, revenue received for these types of consideration is recognized when the service is performed.

Estimates of variable consideration are subject to change as facts and circumstances evolve. As such, the Company will evaluate its estimates of variable consideration that are subject to constraints throughout the contract period and revise estimates, if necessary, at the end of each reporting period.

The Company is a working interest owner of oil and natural gas properties located in Texas and New Mexico. The ownership terms are outlined in joint operating agreements for each well between the operator of the wells and the various interest owners, including the Company, who are considered non-operators of the well. The Company receives revenue each period for its working interest in the well during the period. The revenue received for the working interests from these oil and gas properties does not fall under the scope of the new revenue standard, and therefore, will continue to be reported under current guidance ASC 932-323 *Extractive Activities – Oil and Gas, Investments – Equity Method and Joint Ventures.*

Reimbursement Revenue – 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.

The Company's disaggregated revenue recognized from contracts with customers is included in Note 16.

Accounts Receivable and Contract Liabilities

Accounts receivable is the Company's right to consideration once it becomes unconditional. Payment terms typically range from 30 to 60 days.

Accounts receivable balances were $336 million and $554 million as of December 31, 2019 and 2018, respectively. These balances do not include amounts related to the Company's oil and gas working interests as those contracts are excluded from Topic 606. Accounts receivable balances are included in "Accounts Receivable" in the consolidated balance sheets.

The Company does not have any significant contract asset balances, and as such, contract balances are not presented at the net amount at a contract level. Contract liabilities include prepayments received from customers prior to the requested services being completed. Once the services are complete and have been invoiced, the prepayment is applied against the customer's account to offset the accounts receivable balance. Also included in contract liabilities are payments received from customers for the initial mobilization of newly constructed or upgraded rigs that were moved on location to the initial well site. These mobilization payments are allocated to the overall performance obligation and amortized over the initial term of the contract. During the year ended December 31, 2019 and 2018, approximately $1.0 million and $1.6 million, respectively, was amortized and recorded in drilling revenue.

Total contract liability balances were $2.7 million and $7.6 million as of December 31, 2019 and December 31, 2018, respectively. Contract liability balances are included in "Accounts payable" and "Accrued liabilities" in the consolidated balance sheets.

Contract Costs

Costs incurred for newly constructed or rig upgrades based on a contract with a customer are considered capital improvements and are capitalized to drilling equipment and depreciated over the estimated useful life of the asset.

Practical Expedients Adopted with Topic 606

The Company has elected to adopt the following practical expedients upon the transition date to Topic 606 on January 1, 2018:

- Use of portfolio approach: An entity can apply this guidance to a portfolio of contracts (or performance obligations) with similar characteristics if the entity reasonably expects that the effects on the financial statements of applying this guidance to the portfolio would not differ materially from applying this guidance to the individual contracts (or performance obligations) within that portfolio.

- Excluding disclosure about transaction price: As a practical expedient, an entity need not disclose the information for a performance obligation if either of the following conditions is met:
  a) The performance obligation is part of a contract that has an original expected duration of one year or less.
  b) The entity recognizes revenue from the satisfaction of the performance obligation.
- Excluding sales taxes from the transaction price: The scope of this policy election is the same as the scope of the policy election under previous guidance. This election provides exclusion from the measurement of the transaction price all taxes assessed by a governmental authority that are both imposed on and concurrent with a specific revenue producing transaction and collected by the entity from a customer.
- Costs of obtaining a contract: An entity can immediately expense costs of obtaining a contract if they would be amortized within a year.

4. Inventory

Inventory consisted of the following at December 31, 2019 and 2018 (in thousands):

	2019	2018
Finished goods	$ 105	$ 347
Work-in-process	1,229	6,375
Raw materials and supplies	35,023	58,857
Inventory	$36,357	$65,579

5. Property and Equipment

Property and equipment consisted of the following at December 31, 2019 and 2018 (in thousands):

	2019	2018
Equipment	$ 8,114,326	$ 8,370,933
Oil and natural gas properties	226,646	219,855
Buildings	184,700	186,736
Land	25,747	26,144
Total property and equipment	8,551,419	8,803,668
Less accumulated depreciation, depletion and impairment	(5,244,742)	(4,801,119)
Property and equipment, net	$ 3,306,677	$ 4,002,549

Depreciation, depletion, amortization and impairment — The following table summarizes depreciation, depletion, amortization and impairment expense related to property and equipment, intangible assets and liabilities for 2019, 2018 and 2017 (in thousands):

	2019	2018	2017
Depreciation and impairment expense	$ 974,206	$887,155	$753,510
Amortization expense	17,722	18,197	21,764
Depletion expense	11,945	10,966	8,067
Total	$1,003,873	$916,318	$783,341

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 inactive rigs to working condition and the expected demand for drilling services by rig type. 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 2019, the Company identified 36 legacy non-APEX® rigs and related equipment that would be retired. Based on the strong customer preference across the industry for super-spec drilling rigs, the Company believes the 36 rigs that were retired have limited commercial opportunity. The Company recorded a $173 million charge related to this retirement. In 2018, the Company identified 42 legacy non-APEX® rigs and related equipment that would be retired. Based on the strong customer preference across the industry for super-spec drilling rigs, the Company believes the 42 rigs that were retired had limited commercial opportunity. The Company recorded a $48.4 million charge related to this retirement. In 2017, the Company recorded a 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.

The Company also periodically evaluates its pressure pumping assets for marketability based on the condition of inactive equipment, expenditures that would be necessary to bring the equipment to working condition and the expected demand. The components of equipment that will no longer be marketed are evaluated, and those components with continuing utility will be used as parts to support active equipment. The remaining components of this equipment are retired. In 2019, the Company recorded a charge of $20.5 million for the write-down of pressure pumping equipment compared to a $17.4 million write-down of pressure pumping equipment in 2018. There was no similar charge in 2017.

The Company also periodically evaluates its directional drilling assets. During 2019, the Company recorded a charge of $8.4 million for the write-down of directional drilling equipment. There were no similar charges in 2018 or 2017.

The Company reviews its long-lived assets, including property and equipment, for impairment whenever events or changes in circumstances indicate that the 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.

2019 Triggering Event Assessment

Due to the decline in the market price of the Company's common stock and recent commodity prices, the Company's results of operations for the quarter ended September 30, 2019 and management's expectations of operating results in future periods, the Company lowered its expectations with respect to future activity levels in certain of its operating segments. The Company deemed it necessary to assess the recoverability of its contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups as of September 30, 2019. The Company performed an analysis as required by ASC 360-10-35 to assess the recoverability of the asset groups within its contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments as of September 30, 2019. With respect to these asset groups, 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 asset groups, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the asset groups within the contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments by approximately 35%, 54%, 23% and 7%, respectively.

For the assessment performed in 2019, the expected cash flows for the Company's asset groups included revenue growth rates, operating expense growth rates, and terminal growth rates. Also, the expected cash flows for the contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups were based on the assumption that activity levels in all four segments would generally be lower than levels experienced in 2019 and would begin to recover in late 2020 or 2021 in response to improved oil prices. While the Company believes these assumptions with respect to future oil pricing are reasonable, actual future prices and activity levels may vary significantly from the ones that were assumed. The timeframe over which oil prices and activity levels may recover is highly uncertain.

All of these factors are beyond the Company's control. If the lower oil price environment experienced in 2019 were to last into late 2021 and beyond, the Company's actual cash flows would likely be less than the expected cash flows used in these assessments and could result in impairment charges in the future, and such impairment could be material.

The Company concluded that no triggering events occurred during the quarter ended December 31, 2019 with respect to its asset groups based on the Company's results of operations for the current year, management's expectations of operating results in future periods and the prevailing commodity prices at the time.

Prior Year Triggering Event Assessment

Due to the decline in the market price of the Company's common stock and the deterioration of crude oil prices in the fourth quarter of 2018, the Company lowered its expectations with respect to future activity levels in certain of its operating segments. The Company deemed it necessary to assess the recoverability of its contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups. The Company performed an analysis as required by ASC 360-10-35 to assess the recoverability of the asset groups within its contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments as of December 31, 2018. With respect to these asset groups, 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 asset groups, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the asset groups within the contract drilling, pressure pumping, directional drilling and oilfield rentals operating segments by approximately 38%, 58%, 9% and 23%, respectively.

For the assessment performed in 2018, the expected cash flows for the Company's asset groups included revenue growth rates, operating expense growth rates, and terminal growth rates. Also, the expected cash flows for the contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups were based on the assumption that activity levels in all four segments would generally be lower than levels experienced in the fourth quarter of 2018, and would begin to recover in late 2019 and continue into 2020 in response to improved oil prices and activity levels.

The Company concluded that no triggering events occurred during the year ended December 31, 2017 with respect to its asset groups based on the Company's results of operations for the year ended December 31, 2017 management's expectations of operating results in future periods and the prevailing commodity prices at the time.

6. Goodwill and Intangible Assets

Goodwill — Goodwill by operating segment as of December 31, 2019 and 2018 and changes for the years then ended are as follows (in thousands):

	Contract Drilling	Pressure Pumping	Directional Drilling	Other Operations	Total
Balance, December 31, 2017	$395,060	$ 121,444	$ 88,685	$ 6,284	$ 611,473
Goodwill acquired	—	—	—	9,412	9,412
Measurement period adjustment	—	—	1,000	—	1,000
Impairment	—	(121,444)	(89,685)	—	(211,129)
Balance, December 31, 2018	$395,060	$ —	$ —	$ 15,696	$ 410,756
Measurement period adjustment	—	—	—	$ 2,104	2,104
Impairment	—	—	—	(17,800)	(17,800)
Balance, December 31, 2019	$395,060	$ —	$ —	$ —	$ 395,060

There were no accumulated impairment losses related to goodwill in the contract drilling segment as of December 31, 2019 or 2018.

The change to goodwill in Other Operations in 2019 was primarily a result of a measurement period adjustment related to accrued liabilities, which resulted in a $2.1 million increase from the original purchase price allocation assessed with the Current Power acquisition.

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 impairment testing purposes, goodwill is evaluated at the reporting unit level. The Company's reporting units for impairment testing are 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 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.

Due to the decline in the market price of the Company's common stock and recent commodity prices, the Company's results of operations for the quarter ended September 30, 2019 and management's expectations of operating results in future periods, the Company lowered its expectations with respect to future activity levels in certain of its operating segments. The Company performed a quantitative impairment assessment of its goodwill as of September 30, 2019. In completing the assessment, the fair value of each reporting unit was estimated using the income approach. 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 assumptions included discount rates, revenue growth rates, operating expense growth rates, and terminal growth rates.

Based on the results of the goodwill impairment test as of September 30, 2019, the fair value of the contract drilling reporting unit exceeded its carrying value by approximately 13% and management concluded that no impairment was indicated in its contract drilling reporting unit; however, impairment was indicated in its oilfield rentals and electrical controls and automation reporting units included in the other operations segment. The Company recognized an impairment charge of $17.8 million in 2019 associated with the impairment of all of the goodwill in its oilfield rentals and electrical controls and automation reporting units.

The timeframe over which oil prices and activity levels may recover is highly uncertain. If the lower oil price environment experienced in 2019 were to last into late 2021 and beyond, the Company's actual cash flows would likely be less than the expected cash flows used in these assessments and could result in additional goodwill impairment charges in the future and such impairment could be material.

Due to the decline in the market price of the Company's common stock and the deterioration of crude oil prices in the fourth quarter of 2018, the Company lowered its expectations with respect to future activity levels in certain of its operating segments. The Company performed a quantitative impairment assessment of its goodwill as of December 31, 2018. In completing the assessment, the fair value of each reporting unit was estimated using the income approach. 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 assumptions included discount rates, revenue growth rates, operating expense growth rates, and terminal growth rates.

Based on the results of the goodwill impairment test as of December 31, 2018, the fair value of the contract drilling and oilfield rentals reporting units exceeded their carrying values by approximately 16% and 14%, respectively, and the Company concluded that no impairment was indicated in its contract drilling and oilfield rentals reporting units; however, impairment was indicated in its pressure pumping and directional drilling reporting units. The Company recognized an impairment charge of $211 million associated with the impairment of all of the goodwill in its pressure pumping and directional drilling reporting units.

In connection with the Company's annual goodwill impairment assessment as of December 31, 2019 and 2017, 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 its 2019 and 2017 operating results and forecasted operating results for the respective succeeding year. The Company also considered its overall market capitalization at December 31, 2019 and 2017.

Intangible Assets — In 2018, intangible assets were recorded in the Company's directional drilling operating segment with the acquisition of Superior QC and in other operations with the acquisition of Current Power. 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 for additional information. The Company's intangible assets were recorded at fair value on the date of acquisition and are amortized on a straight line basis. The Company did not incur any costs to renew or extend the term of acquired intangible assets in 2019 or 2018. 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	Directional drilling	3.00
Customer relationships	Other operations	7.00
Developed technology	Directional drilling	5.22
Favorable drilling contracts	Contract drilling	0.83
Internal use software	Directional drilling	5.00

Due to the decline in the market price of the Company's common stock and recent commodity prices, the Company's results of operations for the quarter ended September 30, 2019 and management's expectations of operating results in future periods, the Company lowered its expectations with respect to future activity levels in certain of its operating segments. The Company deemed it necessary to assess the recoverability of its contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups as of September 30, 2019. The assessments of recoverability of the asset groups included the respective intangible assets, and no impairment was indicated. See Note 5 for additional information.

Due to the decline in the market price of the Company's common stock and the deterioration of crude oil prices in the fourth quarter of 2018, the Company lowered its expectations with respect to activity levels in certain of its operating segments. The Company deemed it necessary to assess the recoverability of its contract drilling, pressure pumping, directional drilling and oilfield rentals asset groups as of December 31, 2018. The assessments of recoverability of the asset groups included the respective intangible assets, and no impairment was indicated. See Note 5 for additional information.

The Company concluded that no triggering events necessitating an impairment assessment of the intangible assets had occurred during the quarter ended December 31, 2019 or in 2017.

The gross carrying amount and accumulated amortization of intangible assets as of December 31, 2019 and 2018 are as follows (in thousands):

	2019			2018		
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Customer relationships	$28,000	$(19,710)	$ 8,290	$ 28,000	$(10,719)	$17,281
Developed technology	55,772	(15,386)	40,386	55,772	(6,533)	49,239
Favorable drilling contracts	—	—	—	22,500	(22,500)	—
Internal use software	482	(214)	268	482	(118)	364
	$84,254	$(35,310)	$48,944	$106,754	$(39,870)	$66,884

Amortization expense on intangible assets of approximately $17.9 million, $18.3 million and $24.3 million was recorded for the years ended December 31, 2019, 2018 and 2017, respectively. The remaining amortization expense associated with finite-lived intangible assets is expected to be as follows (in thousands):

Year ending December 31,	
2020	$19,273
2021	12,483
2022	12,461
2023	1,034
2024	1,034
Thereafter	2,659
Total	$48,944

7. Accrued Liabilities

Accrued expenses consisted of the following at December 31, 2019 and 2018 (in thousands):

	2019	2018
Salaries, wages, payroll taxes and benefits	$ 57,615	$ 66,285
Workers' compensation liability	81,112	83,772
Property, sales, use and other taxes	22,404	25,318
Insurance, other than workers' compensation	9,218	9,531
Accrued interest payable	12,021	15,774
Other	37,480	35,266
Accrued liabilities	$219,850	$235,946

8. Long-Term Debt

2019 Term Loan Agreement — On August 22, 2019, the Company entered into a term loan agreement ("Term Loan Agreement") among the Company, as borrower, Wells Fargo Bank, National Association, as administrative agent and lender and the other lender party thereto.

The Term Loan Agreement is a committed senior unsecured term loan facility that permits a single borrowing of up to $150 million, which was drawn in full by the Company on September 23, 2019. Subject to customary conditions, the Company may request that the lenders' aggregate commitments be increased by up to $75 million, not to exceed total commitments of $225 million. The maturity date under the Term Loan Agreement is June 10, 2022. The Company repaid $50 million of the borrowings under the Term Loan Agreement on December 16, 2019.

Loans under the Term Loan Agreement bear interest by reference, at the Company's election, to the LIBOR rate or base rate. The applicable margin on LIBOR rate loans varies from 1.00% to 1.375%, and the applicable margin on base rate loans varies from 0.00% to 0.375%, in each case determined based upon the Company's credit rating. As of December 31, 2019, the applicable margin on LIBOR rate loans and base rate loans was 1.125% and 0.125%, respectively.

The Term Loan Agreement contains representations, warranties, affirmative and negative covenants and events of default and associated remedies that the Company believes are customary for agreements of this nature, including certain restrictions on the ability of the Company and each subsidiary of the Company to incur debt and grant liens. If the Company's credit rating is below investment grade, the Company will become subject to a restricted payment covenant, which would require the Company to have a Pro Forma Debt Service Coverage Ratio (as defined in the Term Loan Agreement) greater than or equal to 1.50 to 1.00 immediately before and immediately after making any restricted payment.

The Term Loan Agreement requires mandatory prepayment in an amount equal to 100% of the net cash proceeds from the issuance of new senior indebtedness (other than certain permitted indebtedness) if the Company's credit rating is below investment grade. The Term Loan Agreement also requires that the Company's total debt to capitalization ratio, expressed as a percentage, not exceed 50%. The Term Loan Agreement generally defines the total 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 end of the most recently ended fiscal quarter.

As of December 31, 2019, the Company had $100 million in borrowings outstanding under the Term Loan Agreement at a LIBOR interest rate of 2.917%.

2018 Credit Agreement — On March 27, 2018, the Company entered into an amended and restated credit agreement (the "Credit Agreement") among the Company, as borrower, Wells Fargo Bank, National Association, as administrative agent, letter of credit issuer, swing line lender and lender, each of the other lenders and letter of credit issuers party thereto, The Bank of Nova Scotia and U.S. Bank National Association, as Co-Syndication Agents, Royal Bank of Canada, as Documentation Agent and Wells Fargo Securities, LLC, The Bank of Nova Scotia and U.S. Bank National Association, as Co-Lead Arrangers and Joint Book Runners.

The Credit Agreement is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to $600 million, including a letter of credit facility that, at any time outstanding, is limited to $150 million and a swing line facility that, at any time outstanding, is limited to $20 million. Subject to customary conditions, the Company may request that the lenders' aggregate commitments be increased by up to $300 million, not to exceed total commitments of $900 million. The original maturity date under the Credit Agreement was March 27, 2023. On March 26, 2019, the Company entered into Amendment No. 1 to Amended and Restated Credit Agreement, which amended the Credit Agreement to, among other things, extend the maturity date under the Credit Agreement from March 27, 2023 to March 27, 2024. The Company has the option, subject to certain conditions, to exercise two one-year extensions of the maturity date.

Loans under the Credit Agreement bear interest by reference, at the Company's election, to the LIBOR rate or base rate. The applicable margin on LIBOR rate loans varies from 1.00% to 2.00% and the applicable margin on base rate loans varies from 0.00% to 1.00%, in each case determined based upon the Company's credit rating. A letter of credit fee is payable by the Company 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 varies from 0.10% to 0.30% based on the Company's credit rating.

No subsidiaries of the Company are currently required to be a guarantor under the Credit Agreement. However, if any subsidiary guarantees or incurs debt in excess of the Priority Debt Basket (as defined in the Credit Agreement), such subsidiary is required to become a guarantor under the Credit Agreement.

The Credit Agreement contains representations, warranties, affirmative and negative covenants and events of default and associated remedies that the Company believes are customary for agreements of this nature, including certain restrictions on the ability of the Company and each subsidiary of the Company to incur debt and grant liens. If the Company's credit rating is below investment grade, the Company will become subject to a restricted payment covenant, which would require the Company to have a Pro Forma Debt Service Coverage Ratio (as defined in the Credit Agreement) greater than or equal to 1.50 to 1.00 immediately before and immediately after making any restricted payment. The Credit Agreement also requires that the Company's total debt to capitalization ratio, expressed as a percentage, not exceed 50%. 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 end of the most recently ended fiscal quarter.

As of December 31, 2019, the Company had no borrowings outstanding under the revolving credit facility. The Company had $81,000 in letters of credit outstanding under the revolving credit facility at December 31, 2019 and, as a result, had available borrowing capacity of approximately $600 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, 2019, the Company had $63.3 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. No subsidiaries of the Company currently guarantee payment under the Credit Agreement.

Series A Senior Notes and Series 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 bore interest at a rate of 4.97% per annum. On September 25, 2019, the Company fully prepaid the Series A Notes. The total amount of the prepayment, including the applicable "make-whole" premium, was approximately $308 million, which represents 100% of the principal and the "make-whole" premium to the prepayment date.

On June 14, 2012, the Company completed the issuance and sale of $300 million in aggregate principal amount of its 4.27% Series B Senior Notes due June 14, 2022 (the "Series B Notes") in a private placement. The Series B Notes bore interest at a rate of 4.27% per annum. On December 16, 2019, the Company fully prepaid the Series B Notes. The total amount of the prepayment, including the applicable "make-whole" premium, was approximately $315 million, which represents 100% of the principal and the "make-whole" premium to the prepayment date.

Primarily as a result of the "make-whole" premiums, the Company incurred a $8.2 million loss on early extinguishment of the Series A Notes in the three months ended September 30, 2019, and a $15.8 million loss on early extinguishment of the Series B Notes in the three months ended December 31, 2019, which were included in "Interest expense, net of amount capitalized" in the consolidated statements of operations.

2028 Senior Notes and 2029 Senior Notes — On January 19, 2018, the Company completed its offering of $525 million in aggregate principal amount of the Company's 3.95% Senior Notes due 2028 (the "2028 Notes"). 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. On November 15, 2019, the Company completed an offering of $350 million in aggregate principal amount of the Company's 5.15% Senior Notes due 2029 (the "2029 Notes"). The net proceeds before offering expenses were approximately $347 million. The Company used a portion of the net proceeds from the offering to prepay its Series B Notes. The remaining net proceeds and available cash on hand was used to repay $50 million of the borrowings under the Term Loan Agreement.

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 Company pays interest on the 2029 Notes on May 15 and November 15 of each year. The 2029 Notes will mature on November 15, 2029. The 2029 Notes bear interest at a rate of 5.15% per annum.

The 2028 Notes and 2029 Notes (together, the "Senior 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 Senior 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 Senior Notes will be structurally subordinated to the liabilities (including trade payables) of the Company's subsidiaries that do not guarantee the Senior Notes. No subsidiaries of the Company are currently required to be a guarantor under the Senior Notes. If subsidiaries of the Company guarantee the Senior Notes in the future, such guarantees (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.

The Company, at its option, may redeem the Senior Notes in whole or in part, at any time or from time to time at a redemption price equal to 100% of the principal amount of such Senior Notes to be redeemed, plus accrued and unpaid interest, if any, on those Senior Notes to the redemption date, plus a "make-whole" premium. Additionally, commencing on November 1, 2027, in the case of the 2028 Notes, and on August 15, 2029, in the case of the 2029 Notes, the Company, at its option, may redeem the respective Senior Notes in whole or in part, at a redemption price equal to 100% of the principal amount of the Senior Notes to be redeemed, plus accrued and unpaid interest, if any, on those Senior Notes to the redemption date.

The indentures pursuant to which the Senior Notes were issued include 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 indentures, each holder of the Senior Notes may require the Company to purchase all or a portion of such holder's Senior 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 indentures also provide 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 Senior Notes to become or to be declared due and payable.

Debt issuance costs — The Company incurred approximately $151,000 debt issuance costs in connection with the Term Loan Agreement. The Company incurred approximately $4.6 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. The Company incurred approximately $1.6 million in debt issuance costs in connection with the 2028 Notes and approximately $1.0 million in debt issuance costs in connection with the 2029 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 $2.0 million, $2.0 million and $2.6 million for the years ended December 31, 2019, 2018 and 2017, respectively. Amortization of debt issuance costs for the year ended December 31, 2019 includes $185,000 of debt issuance costs that were expensed as a result of the Series A Notes prepayment, $394,000 of debt issuance costs that were expensed as a result of the Series B Notes prepayment and approximately $50,000 of debt issuance costs that were expensed as a result of the Term Loan Agreement partial repayment. Amortization of debt issuance costs for the year ended December 31, 2018 includes $317,000 of debt issuance costs related to commitments by lenders under the Company's previous credit agreement who did not participate in the Credit Agreement.

Presented below is a schedule of the principal repayment requirements of long-term debt by fiscal year as of December 31, 2019 (in thousands):

Year ending December 31,	
2020	$ —
2021	—
2022	100,000
2023	—
2024	—
Thereafter	875,000
Total	$975,000

9. Commitments, Contingencies and Other Matters

Commitments – As of December 31, 2019, the Company maintained letters of credit in the aggregate amount of $63.4 million primarily 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, 2019, no amounts had been drawn under the letters of credit.

As of December 31, 2019, the Company had commitments to purchase major equipment and make investments totaling approximately $51 million for its drilling, pressure pumping, directional drilling and oilfield rentals businesses.

The Company's pressure pumping business has entered into agreements to purchase minimum quantities of proppants and chemicals from certain vendors. The agreements expire in years 2020 through 2023. As of December 31, 2019, the remaining obligation under these agreements was approximately $37.8 million, of which approximately $15.8 million relates to purchases required during 2020. In the event 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. In 2017, the Company entered into a capacity reservation agreement that required a cash deposit to increase the Company's access to finer grades of sand for its pressure pumping business. As market prices for sand substantially decreased since 2017, the Company purchased lower cost sand outside of this capacity reservation contract and recorded a charge of $12.7 million in the second quarter of 2019 to revalue the deposit to its expected realizable value.

Contingencies – The Company's operations are subject to many hazards inherent in the businesses in which it operates, including inclement weather, blowouts, explosions, fires, loss of well control, equipment failure, 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. An accident or other event resulting in significant environmental or property damage, or injuries or fatalities involving the Company's employees or other persons could also trigger investigations by federal, state or local authorities. Such an accident or other event could cause the Company to incur substantial expenses in connection with the investigation, remediation and resolution, as well as cause lasting damage to the Company's reputation, loss of customers and an inability to obtain insurance.

The Company has indemnification agreements with many of its customers, and also maintains liability and other forms of insurance. In general, the Company's contracts typically contain provisions requiring its customers to indemnify the Company for, among other things, reservoir and certain pollution damage. The Company's right to indemnification may, however, be unenforceable or limited due to negligent or willful acts or omissions 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 services 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 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 maintains insurance coverage of types and amounts that the Company believes to be customary in the industry, but is not fully insured against all risks, either because insurance is not available or because of the high premium costs. The insurance coverage that the Company maintains includes insurance for fire, windstorm and other risks of physical loss to its equipment and certain other assets, employer's liability, automobile liability, commercial general liability, workers' compensation and insurance for other specific risks. The Company cannot assure, however, that any insurance obtained 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 the Company. While the Company carries insurance to cover physical damage to, or loss of, a substantial portion of its equipment and certain other assets, such insurance does not cover the full replacement cost of such equipment or other assets. 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 $10.0 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 most cybersecurity risks, and does not carry a significant amount of insurance to cover risks of underground reservoir damage.

On July 18, 2018, the U.S. Occupational Safety and Health Administration ("OSHA") issued a citation containing alleged violations, proposed abatement dates and an aggregate proposed penalty of approximately $74,000 in connection with an accident at a drilling site in Pittsburg County, Oklahoma that resulted in the losses of life of five people, including three of the Company's employees. The Company filed a notice of contest with OSHA that contested all citation items, abatement dates and proposed penalties. The Department of Labor (the "DOL") filed a complaint on OSHA's behalf seeking enforcement of the citation as issued, and the Company filed an answer to the complaint. In October 2019, the Company and the DOL agreed to a settlement of all but one of the citation items, and a hearing on the remaining citation item was held before an administrative law judge. The Company and the DOL will file post-hearing briefs and await the judge's determination.

The Company is party to various other 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, cash flows or results of operations.

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.

10. 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, 2019, 2018 and 2017 as follows:

	Per Share	Total (in thousands)
2019		
Paid on March 21, 2019	$0.04	$ 8,499
Paid on June 20, 2019	0.04	8,344
Paid on September 19, 2019	0.04	7,847
Paid on December 19, 2019	0.04	7,738
Total cash dividends	$0.16	$32,428
2018		
Paid on March 22, 2018	$0.02	$ 4,443
Paid on June 21, 2018	0.04	8,832
Paid on September 20, 2018	0.04	8,685
Paid on December 20, 2018	0.04	8,629
Total cash dividends	$0.14	$30,589
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

On February 5, 2020, the Company's Board of Directors approved a cash dividend on its common stock in the amount of $0.04 per share to be paid on March 19, 2020 to holders of record as of March 5, 2020. 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 authorized purchases of up to $200 million of the Company's common stock in open market or privately negotiated transactions. On July 25, 2018, the Company's Board of Directors approved an increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. On February 6, 2019, the Company's Board of Directors approved another increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. On July 24, 2019, the Company's Board of Directors approved another increase of the authorization under the stock buyback program to allow for $250 million of future share repurchases. 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. There is no expiration date associated with the buyback program. As of December 31, 2019, the Company had remaining authorization to purchase approximately $150 million of the Company's outstanding common stock under the stock buyback program. Shares of stock purchased under the buyback program are held as treasury shares.

The Company acquired shares of stock from directors in 2017 and employees during 2019, 2018, and 2017 that are accounted for as treasury stock. Certain of these shares were acquired to satisfy the exercise price and employees' tax withholding obligations upon 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 and restricted stock units. These shares were acquired at fair market value. These acquisitions were made pursuant to the terms of the Plan (as defined below) and not pursuant to the stock buyback program.

Treasury stock acquisitions during the years ended December 31, 2019, 2018 and 2017 were as follows (dollars in thousands):

	2019		2018		2017	
	Shares	Cost	Shares	Cost	Shares	Cost
Treasury shares at beginning of period	53,701,096	$1,080,448	43,802,611	$ 918,711	43,392,617	$911,094
Purchases pursuant to stock buyback program	22,566,331	250,109	9,331,131	150,497	5,503	109
Acquisitions pursuant to long-term incentive plan	1,037,947	14,205	567,354	11,240	404,491	7,508
Other	31,013	372	—	—	—	—
Treasury shares at end of period	77,336,387	$1,345,134	53,701,096	$1,080,448	43,802,611	$918,711

11. 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 include equity instruments in the form of stock options, restricted stock or restricted stock units that have included service conditions and, in certain cases, performance conditions. The Company's share-based awards also include share-settled performance unit awards. Share-settled performance unit awards are accounted for as equity awards. 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 Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan (the "2014 Plan") was originally approved by the Company's stockholders effective as of April 17, 2014 and authorized 9.1 million shares for issuance. 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 by 9.8 million shares. On June 6, 2019, the Company's stockholders approved an amendment to the Amended and Restated Plan to increase the number of shares available for issuance under the plan by 9.5 million shares and to extend the latest date on which awards may be granted under the Amended and Restated Plan to June 6, 2029 (the "Amendment" and the Amended and Restated Plan, as amended by the Amendment, the "Plan"). The aggregate number of shares of the Company's common stock authorized for grant under the Plan is 28.4 million. The Company's share-based compensation plans at December 31, 2019 are as follows:

Plan Name	Shares Authorized for Grant	Shares Underlying Awards Outstanding	Shares Available for Grant
Amended and Restated Plan	28,400,000	6,320,440	8,331,502
Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, as amended	—	2,533,500	—

A summary of the 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, 2019, 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 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.

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 such 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 years ended December 31, 2019, 2018 and 2017.

Stock option activity for the year ended December 31, 2019 follows:

	Shares	Weighted Average Exercise Price Per Share
Outstanding at beginning of year	5,501,150	$19.63
Exercised	(700,000)	$13.17
Expired	(35,000)	$14.95
Outstanding at end of year	4,766,150	$20.62
Exercisable at end of year	4,736,150	$20.63

Options outstanding at December 31, 2019 have no intrinsic value and a weighted-average remaining contractual term of 3.62 years. Options exercisable at December 31, 2019 have no intrinsic value and a weighted-average remaining contractual term of 3.60 years. Additional information with respect to options granted, vested and exercised during the years ended December 31, 2019, 2018 and 2017 follows (in thousands, except per share data):

	2019	2018	2017
Weighted-average grant date fair value of stock options granted (per share)	NA	NA	NA
Aggregate grant date fair value of stock options vested during the year	$543	$1,954	$4,565
Aggregate intrinsic value of stock options exercised	$ —	$ —	$ 209

As of December 31, 2019, options to purchase 30,000 shares were outstanding and not vested. All of these non-vested options are expected to ultimately vest. Additional information as of December 31, 2019 with respect to these non-vested options follows (dollars in thousands):

Aggregate intrinsic value	$—
Weighted-average remaining contractual term	6.71 years
Weighted-average remaining expected term	1.71 years
Weighted-average remaining vesting period	1.71 years
Unrecognized compensation cost	$151

Restricted Stock — For all restricted stock awards made 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, 2019 follows:

	Shares	Weighted Average Grant Date Fair Value Per Share
Non-vested restricted stock outstanding at beginning of year	436,224	$21.41
Vested	(362,673)	$21.38
Forfeited	(1,500)	$21.71
Non-vested restricted stock outstanding at end of year	72,051	$21.59

As of December 31, 2019, approximately 72,000 shares of non-vested restricted stock outstanding are expected to vest. Additional information as of December 31, 2019 with respect to these non-vested shares follows (dollars in thousands):

Aggregate intrinsic value	$ 757
Weighted-average remaining vesting period	.3 year
Unrecognized compensation cost	$1,247

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. Forfeitable dividend equivalents are accrued on certain 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, 2019 follows:

	Time Based	Performance Based	Weighted Average Grant Date Fair Value Per Share
Non-vested restricted stock units outstanding at beginning of year	2,602,608	435,315	$18.95
Granted	1,505,048	—	$12.40
Vested (1)	(1,135,231)	(38,000)	$19.19
Forfeited	(340,699)	—	$17.08
Non-vested restricted stock units outstanding at end of year	2,631,726	397,315	$15.81

(1) All of the performance-based restricted stock units that vested during 2019 were granted in 2017.

As of December 31, 2019, approximately 2.9 million non-vested restricted stock units outstanding are expected to vest. Additional information as of December 31, 2019 with respect to these non-vested restricted stock units follows (dollars in thousands):

Aggregate intrinsic value	$30,938
Weighted-average remaining vesting period	1.9 years
Unrecognized compensation cost	$36,933

Performance Unit Awards. The Company has granted share-settled performance unit awards to certain employees (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 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. For the Performance Units granted in May 2017 and April 2018, 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. For the Performance Units granted in April 2019, the recipients will receive 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 55th 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, then 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 target percentile, or the target and 75th percentile, then the shares to be received by the recipients will be determined using linear interpolation for levels of achievement between these points.

For the Performance Units awarded prior to 2016, there was no payout unless the Company's total shareholder return was positive and, when compared to the peer group was at or above the 25th percentile. For the Performance Units granted in April 2016, if the Company's total shareholder return was negative, and, when compared to the peer group was at or above the 25th percentile, then the recipients would 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 and April 2018, the payout is based on relative performance and does not have an absolute performance requirement. For the Performance Units granted in April 2019, the payout shall not exceed the target number of shares if the Company's total shareholder return is negative or zero.

The total target number of shares with respect to the Performance Units for the years 2014-2019 is set forth below:

	2019 Performance Unit Awards	2018 Performance Unit Awards	2017 Performance Unit Awards	2016 Performance Unit Awards	2015 Performance Unit Awards	2014 Performance Unit Awards
Target number of shares	489,800	310,700	186,198	185,000	190,600	154,000

The 2014 Performance Units settled with a negative total shareholder return, so there was no payout under such Performance Units. In April 2018, 381,200 shares were issued to settle the 2015 Performance Units. In April 2019, 185,000 shares were issued to settle the 2016 Performance Units. The Performance Units granted in 2017, 2018, and 2019 have not reached the end of their respective performance periods.

Because the Performance Units are share-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):

	2019 Performance Unit Awards	2018 Performance Unit Awards	2017 Performance Unit Awards	2016 Performance Unit Awards	2015 Performance Unit Awards	2014 Performance Unit Awards
Aggregate fair value at date of grant	$9,958	$8,004	$5,780	$3,854	$4,052	$5,388

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):

	2019 Performance Unit Awards	2018 Performance Unit Awards	2017 Performance Unit Awards	2016 Performance Unit Awards	2015 Performance Unit Awards	2014 Performance Unit Awards
Year ended December 31, 2019	$2,489	$2,668	$1,927	$ 321	NA	NA
Year ended December 31, 2018	NA	$2,001	$1,927	$1,285	$ 338	NA
Year ended December 31, 2017	NA	NA	$1,284	$1,285	$1,351	$449

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.

12. Leases

ASC Topic 842 Leases

On January 1, 2019, the Company adopted the new lease guidance under Topic 842, *Leases*, using the modified retrospective approach to each lease that existed at the date of initial application as well as leases entered into after that date. The Company has elected to report all leases at the beginning of the period of adoption and not restate its comparative periods. This standard does not apply to leases to explore for or use minerals, oil, natural gas and similar non-regenerative resources, including the intangible right to explore for those natural resources and rights to use the land in which those natural resources are contained.

The Company has entered into operating leases for operating locations, corporate offices and certain operating equipment. These leases have remaining lease terms of one month to nine years as of December 31, 2019. Currently, the Company does not have any finance leases. Renewal options are included in the right of use asset and lease liability if it is reasonably certain that the Company will exercise the option. The Company has elected the short-term lease recognition practical expedient whereby right of use assets and lease liabilities are not recognized for leasing arrangements with an initial term of one year or less.

Topic 842 requires that lessees and lessors discount lease payments at the lease commencement date using the rate implicit in the lease, if available, or the lessee's incremental borrowing rate. The Company uses the implicit rate when readily determinable. If the implicit rate is not readily determinable, the Company uses its incremental borrowing rate based on the information available at the commencement date in the determination of the present value of future lease payments.

In the fourth quarter of 2019 the Company entered into a sale-leaseback transaction that qualified as a sale. The Company sold a facility for proceeds of $10.2 million and concurrently entered into an operating lease agreement with the unrelated third-party for certain floors of the building for a 58-month term. The associated gain on sale of approximately $800,000 is included in "Other operating expenses (income), net" in the consolidated statements of operations.

For the year ended December 31, 2019 the Company has entered into 3 new facility leases and recorded an increase to the operating lease right-of-use assets and corresponding operating lease liabilities of approximately \$3.8 million. The Company also extended 9 facilities leases and recorded an increase to the operating lease right-of-use assets and corresponding operating lease liabilities of approximately \$7.1 million.

Practical Expedients Adopted with Topic 842

The Company has elected to adopt the following practical expedients upon the transition date to Topic 842 on January 1, 2019:

- Transitional practical expedients package: An entity may elect to apply the listed practical expedients as a package to all the leases that commenced before the effective date. The practical expedients are:
  - a) The entity need not reassess whether any expired or existing contracts are or contain leases;
  - b) The entity need not reassess the lease classification for expired or existing contracts;
  - c) The entity need not reassess initial direct costs for any existing leases.
- Use of portfolio approach: An entity can apply this guidance to a portfolio of leases with similar characteristics if the entity reasonably expects that the application of the leases model to the portfolio would not differ materially from the application of the leases model to the individual leases in that portfolio. This approach can also be applied to other aspects of the leases guidance for which lessees/lessors need to make judgments and estimates, such as determining the discount rate and determining and reassessing the lease term.
- Lease and non-lease components: As a practical expedient, lease and non-lease components may be combined where the revenue recognition pattern is the same and where the lease component, when accounted for separately, would be considered an operating lease. The Company's contract drilling, pressure pumping and directional drilling contracts contain a lease component related to the underlying equipment utilized, in addition to the service component provided by the Company's crews and expertise to operate the related equipment. The Company has concluded that the non-lease service of operating its equipment and providing expertise in the services provided to customers is predominant in the Company's drilling, pressure pumping and directional drilling contracts. With the election of this practical expedient, the Company will continue to present a single performance obligation for these contracts under the revenue guidance in ASC 606.

Lease expense consisted of the following for the year ended December 31, 2019 (in thousands):

	Year Ended December 31, 2019
Operating lease cost	\$10,944
Short-term lease expense (1)	440
Total lease expense	\$11,384

(1) Short-term lease expense represents expense related to leases with a contract term of one year or less.

Supplemental cash flow information related to leases for the year ended December 31, 2019 is as follows (in thousands):

	Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows from operating leases	\$10,033
Right of use assets obtained in exchange for lease obligations:	
Operating leases	\$10,870

Supplemental balance sheet information related to leases as of December 31, 2019 is as follows:

	December 31, 2019
Weighted Average Remaining Lease Term:	
Operating leases	5.3 years
Weighted Average Discount Rate:	
Operating leases	4.2%

Maturities of operating lease liabilities as of December 31, 2019 are as follows (in thousands):

Year ending December 31,	
2020	$11,212
2021	8,484
2022	6,220
2023	3,955
2024	3,055
Thereafter	7,883
Total lease payments	40,809
Less imputed interest	(4,230)
Total	$36,579

13. Income Taxes

Components of the income tax provision applicable to federal, state and foreign income taxes for the years ended December 31, 2019, 2018 and 2017 are as follows (in thousands):

	2019	2018	2017
Federal income tax benefit:			
Current	$ (1,976)	$ (3,954)	$ (42)
Deferred	(90,441)	(35,081)	(335,106)
	(92,417)	(39,035)	(335,148)
State income tax expense (benefit):			
Current	851	1,704	(215)
Deferred	(11,593)	(11,147)	4,511
	(10,742)	(9,443)	4,296
Foreign income tax expense (benefit):			
Current	(348)	(2,552)	(3,108)
Deferred	(1,168)	5,043	249
	(1,516)	2,491	(2,859)
Total income tax benefit:			
Current	(1,473)	(4,802)	(3,365)
Deferred	(103,202)	(41,185)	(330,346)
Total income tax benefit:	$(104,675)	$(45,987)	$(333,711)

Loss before income taxes for the U.S. for years ended December 31, 2019, 2018, and 2017 are $499.9 million, $343.1 million, and $312.9 million, respectively. Loss before income taxes for non-U.S. jurisdictions for years ended December 31, 2019, 2018, and 2017 are $30.5 million, $24.3 million, and $14.9 million, respectively. The difference between the statutory federal income tax rate and the effective income tax rate for the years ended December 31, 2019, 2018 and 2017 is summarized as follows:

	2019	2018	2017
Statutory tax rate	21.0%	21.0%	35.0%
State income taxes - net of the federal income tax benefit	1.7	1.2	1.9
Goodwill impairment	(0.7)	(6.9)	—
Permanent differences	(0.5)	(0.6)	(1.3)
Tax effects of tax reform	—	(1.3)	66.7
Share-based payments	(0.7)	(0.1)	3.6
Acquisition related differences	—	—	(3.3)
Valuation allowance	(0.8)	(3.7)	—
State deferred tax remeasurement	(1.1)	2.3	—
Other differences, net	0.8	0.6	(0.8)
Effective tax rate	19.7%	12.5%	101.8%

The effective tax rate increased by approximately 7.2% to 19.7% for 2019 compared to 12.5% for 2018. This difference was primarily due to higher goodwill impairment charges in 2018 relative to 2019, which are not deductible for tax purposes. These charges resulted in a 6.9% decrease to the effective tax rate in 2018, as compared to a 0.7% decrease to the effective tax rate in 2019. Another factor was valuation allowances being established against deferred tax assets in certain state and non-U.S. jurisdictions, which were higher in 2018 as compared to 2019. These resulted in a 3.7% decrease to the effective tax rate in 2018, as compared to a 0.8% decrease to the rate in 2019.

The Company continues to monitor income tax developments in the United States and other countries affecting the Company. In December 2017, the United States enacted U.S. Tax Reform, which materially impacted the consolidated financial statements by decreasing the U.S. corporate statutory tax rate and significantly affecting future periods. The Company expects several proposed U.S. Treasury regulations under U.S. Tax Reform that were issued during 2018 and 2019 to be finalized during 2020. The Company will incorporate into its future financial statements the impacts, if any, of these regulations and additional authoritative guidance when finalized.

The Company continues to elect permanent reinvestment of unremitted earnings in Canada effective January 1, 2010, and it intends to do so for the foreseeable future. If the Company were to repatriate earnings, in the form of dividends or otherwise, it might be subject to certain income taxes (subject to an adjustment for foreign tax credits) and withholding taxes payable.

The tax effect of significant temporary differences representing deferred tax assets and liabilities at December 31, 2019 and 2018 are as follows (in thousands):

	2019	2018
Deferred tax assets:		
Net operating loss carryforwards	$ 375,308	$ 324,389
Tax credits	4,138	6,404
Expense associated with stock options and restricted stock	10,561	13,375
Workers' compensation allowance	19,536	19,900
Other deferred tax asset	21,698	22,423
	431,241	386,491
Less:		
Valuation allowance	(17,231)	(13,232)
Total deferred tax assets	414,010	373,259
Deferred tax liabilities:		
Property and equipment basis difference	(607,785)	(669,196)
Other	(9,184)	(10,224)
Total deferred tax liabilities	(616,969)	(679,420)
Net deferred tax liability	$(202,959)	$(306,161)

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. The Company considers carryback availability, the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. In 2019, the Company recorded an additional $4 million of valuation allowances against its net deferred tax assets, primarily relating to certain Canadian subsidiaries. These valuation allowances were recorded due to a change in judgment as to the realizability of these assets in future tax years.

For income tax purposes, the Company has approximately $1.4 billion of gross federal net operating losses, approximately $47.4 million of gross Canadian net operating losses and approximately $847 million of post-apportionment state net operating losses as of December 31, 2019, before valuation allowances. The majority of federal net operating losses will expire in varying amounts, if unused, between 2034 and 2037. Federal net operating losses generated in 2018 and 2019 can be carried forward indefinitely. Canadian net operating losses will expire in varying amounts, if unused, between 2036 and 2039. State net operating losses will expire in varying amounts, if unused, between 2023 and 2039.

As of December 31, 2019, 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, 2019, the tax years ended December 31, 2014 through December 31, 2018 are open for examination by U.S. taxing authorities. As of December 31, 2019, the tax years ended December 31, 2012 through December 31, 2018 are open for examination by Canadian taxing authorities.

14. Earnings Per 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, performance units and restricted stock units. The dilutive effect of stock options, performance units 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, 2019, 2018 and 2017, 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):

	2019	2018	2017
BASIC EPS:			
Net income (loss)	$(425,703)	$(321,421)	$ 5,910
Adjust for (income) loss attributed to holders of non-vested restricted stock	—	—	(170)
Income (loss) attributed to common stockholders	$(425,703)	$(321,421)	$ 5,740
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	203,039	218,643	198,447
Basic net income (loss) per common share	$ (2.10)	$ (1.47)	$ 0.03
DILUTED EPS:			
Income (loss) attributed to common stockholders	$(425,703)	$(321,421)	$ 5,740
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	203,039	218,643	198,447
Add dilutive effect of potential common shares	—	—	1,435
Weighted average number of diluted common shares outstanding	203,039	218,643	199,882
Diluted net income (loss) per common share	$ (2.10)	$ (1.47)	$ 0.03
Potentially dilutive securities excluded as anti-dilutive	9,195	9,762	3,289

15. Employee Benefits

The Company maintains a 401(k) plan for all eligible employees. The Company’s operating results include expenses of approximately $13.2 million in 2019, $14.3 million in 2018 and $8.7 million in 2017 for the Company’s contributions to the plan.

16. Business Segments

At December 31, 2019, the Company had three reportable 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 and has a separate management team that reports 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, 2019, the Company had 216 marketed land-based drilling rigs in the continental United States and western Canada.

For the years ended December 31, 2019, 2018 and, 2017, contract drilling revenue earned in Canada was $4.7 million, $9.3 million and $13.7 million, respectively. Additionally, long-lived assets within the contract drilling segment located in Canada totaled $20.1 million and $26.2 million as of December 31, 2019 and 2018, 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. Substantially all of the revenue in the pressure pumping segment is from well stimulation services (such as hydraulic fracturing) 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. The Company also provides wireline and cementing services through its pressure pumping segment. 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. Substantially all of the revenue in the directional drilling segment is from directional drilling, downhole performance motors and measurement-while-drilling services, which are sold as a bundle.

Major Customer — During 2019, 2018 and 2017, no single customer accounted for more than 10% of the Company's consolidated operating revenues.

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

	Year Ended December 31,		
	2019	2018	2017
Revenues:			
Contract drilling	$1,309,988	$1,432,012	$1,041,492
Pressure pumping	868,694	1,573,396	1,200,311
Directional drilling	188,786	209,275	45,580
Other operations (1)	122,885	131,028	76,781
Elimination of intercompany revenues (2)	(19,668)	(18,714)	(7,480)
Total revenues	$2,470,685	$3,326,997	$2,356,684
Income (loss) before income taxes:			
Contract drilling	$ (151,329)	$ (33,115)	$ (171,897)
Pressure pumping	(102,701)	(77,328)	21,028
Directional drilling	(52,724)	(117,497)	(21)
Other operations	(54,725)	(18,221)	(20,813)
Corporate	(96,719)	(93,585)	(152,792)
Other operating income, net (3)	2,305	17,569	31,957
Provision for bad debts	(5,683)	—	—
Interest income	6,013	5,597	1,866
Interest expense	(75,204)	(51,578)	(37,472)
Other	389	750	343
Loss before income taxes	$ (530,378)	$ (367,408)	$ (327,801)
Depreciation, depletion, amortization and impairment:			
Contract drilling	$ 668,007	$ 571,607	$ 538,891
Pressure pumping	233,952	250,010	198,006
Directional drilling	52,223	45,317	9,347
Other operations	42,803	41,512	29,402
Corporate	6,888	7,872	7,695
Total depreciation, depletion, amortization and impairment	$1,003,873	$ 916,318	$ 783,341
Capital expenditures:			
Contract drilling	$ 194,416	$ 394,595	$ 354,425
Pressure pumping	105,803	173,848	171,436
Directional drilling	15,549	35,929	7,795
Other operations	27,132	34,660	31,547
Corporate	4,612	2,426	1,884
Total capital expenditures	$ 347,512	$ 641,458	$ 567,087
Identifiable assets:			
Contract drilling	$3,190,463	$3,817,638	$3,931,994
Pressure pumping	695,570	921,237	1,209,424
Directional drilling	164,273	239,341	301,275
Other operations	128,290	177,374	172,094
Corporate (4)	261,019	314,276	144,069
Total assets	$4,439,615	$5,469,866	$5,758,856

(1) Other operations includes the Company's oilfield rentals business, drilling equipment service business, the electrical controls and automation business, the oil and natural gas working interests and Middle East organizational activities.

(2) Intercompany revenues consists of contract drilling and revenues from other operations for services provided to contract drilling, pressure pumping and within other operations.
(3) Other operating income, net includes net gains associated with the disposal of assets related to corporate strategy decisions of the executive management group. Accordingly, the related gains have been excluded from the operating results of specific segments. This caption also includes certain legal-related expenses and settlements, net of insurance reimbursements and certain research and development expenses.
(4) Corporate assets primarily include cash on hand and certain property and equipment.

17. 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, 2019 and 2018, the Company's demand deposits and temporary cash investments consisted of the following (in thousands):

	2019	2018
Deposits in FDIC and SIPC-insured institutions under insurance limits	$ 1,250	$ 750
Deposits in FDIC and SIPC-insured institutions over insurance limits	179,375	229,132
Deposits in foreign banks	2,309	22,698
	182,934	252,580
Less outstanding checks and other reconciling items	(8,749)	(7,551)
Cash and cash equivalents	$174,185	$245,029

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. A $5.7 million provision for bad debts was recognized in 2019 with respect to accounts receivable balances that were estimated to be uncollectible. No expense for bad debts was recognized in 2018 and 2017.

18. 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, 2019 and 2018 is set forth below (in thousands):

	December 31, 2019		December 31, 2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
3.95% Senior Notes	$525,000	$511,485	$ 525,000	$ 482,488
5.15% Senior Notes	350,000	358,864	—	—
4.97% Series A Senior Notes	—	—	300,000	300,043
4.27% Series B Senior Notes	—	—	300,000	293,900
2019 Term Loan	100,000	100,000	—	—
Total debt	$975,000	$970,349	$1,125,000	$1,076,431

The fair value of the 3.95% Senior Notes at December 31, 2019 and December 31, 2018 are based on discounted cash flows associated with the notes using the 4.33% market rate of interest at December 31, 2019 and the 5.07% market rate of interest at December 31, 2018. The fair value of the 5.15% Senior Notes at December 31, 2019 is based on discounted cash flows associated with the notes using the 4.81% market rate of interest at December 31, 2019. The fair value estimates of the 3.95% Senior Notes and the 5.15% Senior Notes are considered Level 1 fair value estimates in the fair value hierarchy of fair value accounting. The fair values of the Series A Notes and Series B Notes at December 31, 2018 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 rate used in measuring this fair value was 4.97% at December 31, 2018. For the Series B Notes, the current market rate used in measuring this fair value was 4.92% at December 31, 2018. 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. The carrying values of the balance outstanding at December 31, 2019 under the Term Loan Agreement approximated its fair value as the instrument has a floating interest rate.

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

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2019				
Operating revenues	$704,171	$675,765	$ 598,452	$ 492,297
Operating loss	(23,383)	(48,125)	(307,305)	(82,763)
Net loss	(28,614)	(49,447)	(261,719)	(85,923)
Net loss per common share:				
Basic	$ (0.14)	$ (0.24)	$ (1.31)	$ (0.44)
Diluted	$ (0.14)	$ (0.24)	$ (1.31)	$ (0.44)
2018				
Operating revenues	$809,164	$854,418	$ 867,478	$ 795,937
Operating loss	(22,102)	(9,004)	(80,281)	(210,790)
Net loss	(34,417)	(10,713)	(75,042)	(201,249)
Net loss per common share:				
Basic	$ (0.16)	$ (0.05)	$ (0.34)	$ (0.93)
Diluted	$ (0.16)	$ (0.05)	$ (0.34)	$ (0.93)

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, 2019				
Deducted from asset accounts:				
Allowance for doubtful accounts	$2,312	$5,683	$(1,479)	$6,516
Year Ended December 31, 2018				
Deducted from asset accounts:				
Allowance for doubtful accounts	$2,323	$ —	$ (11)	$2,312
Year Ended December 31, 2017				
Deducted from asset accounts:				
Allowance for doubtful accounts	$3,191	$ —	$ (868)	$2,323

(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 13, 2020

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 13, 2020.

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/ Tiffany Thom Cepak Tiffany Thom Cepak	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/ Janeen S. Judah Janeen S. Judah	Director