PATTERSON UTI ENERGY INC
Form 10-K
February 10, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015

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.)

450 Gears Road, Suite 500, Houston, Texas	77067
(Address of principal executive offices)	(Zip Code)

Registrant’s telephone number, including area code:

(281) 765-7100

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

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

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

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x 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 x

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 x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x or No ¨

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

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2015, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $2.7 billion, calculated by reference to the closing price of $18.82 for the common stock on the Nasdaq Global Select Market on that date.

As of February 4, 2016, the registrant had outstanding 147,179,777 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 2016 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this “Report”) and other public filings and press releases by us contain “forward-looking statements” within the meaning of the Securities Act of 1933, as amended (the “Securities Act”), the Securities Exchange Act of 1934, as amended (the “Exchange Act”), and the Private Securities Litigation Reform Act of 1995, as amended. These “forward-looking statements” involve risk and uncertainty. These forward-looking statements include, without limitation, statements relating to: liquidity; revenue and cost expectations and backlog; financing of operations; oil and natural gas prices; 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 “anticipates,” “believes,” “budgeted,” “continue,” “could,” “estimates,” “expects,” “intends,” “may,” “plans,” “project,” “should,” “strategy,” 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. Forward-looking statements may be made orally or in writing, including, but not limited to, 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.

Forward-looking statements are not guarantees of future performance and a variety of factors could cause actual results to differ materially from the anticipated or expected results expressed in or suggested by these forward-looking statements. Factors that might cause or contribute to such differences include, but are not limited to, 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, utilization, margins and planned capital expenditures, global economic conditions, excess availability of land drilling rigs and pressure pumping equipment, including as a result of reactivation or construction, equipment specialization and new technologies, competition, adverse industry conditions, adverse credit and equity market conditions, failure by our customers to pay us or satisfy their contractual obligations (particularly with respect to fixed-term contracts), difficulty in building and deploying new equipment and integrating acquisitions, shortages, delays in delivery and interruptions in supply of equipment, supplies and materials, weather, loss of key customers, liabilities from operations for which we do not have and receive full indemnification or insurance, ability to effectively identify and enter new markets, governmental regulation, ability to realize backlog, ability to retain management and field personnel, legal procedings and other factors. Refer to “Risk Factors” contained in Item 1A of this Report for a more complete discussion of factors that might affect our performance and financial results. You are cautioned not to place undue reliance on any of our forward-looking statements. These forward-looking statements are intended to relay our expectations about the future, and speak only as of the date they are made. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, changes in internal estimates or otherwise, except as required by law.

PART I

Item 1. Business

Available Information

This Report, along with our Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, are available free of charge through our internet website (www.patenergy.com) as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The information contained on our website is not part of this Report or other filings that we make with the SEC. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Overview

We own and operate in the United States one of the largest fleets of land-based drilling rigs and a large fleet of pressure pumping equipment. We were formed in 1978 and reincorporated in 1993 as a Delaware corporation. Patterson Energy, Inc. and UTI Energy Corp. merged in 2001 to form Patterson-UTI Energy, Inc. Our corporate headquarters are in Houston, Texas.

Our contract drilling business operates in the continental United States and western Canada, and we are pursuing contract drilling opportunities outside of North America. As of December 31, 2015, we had a drilling fleet that consisted of 221 marketable 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. A drilling rig is considered marketable at a point in time if it is operating or can be made ready to operate without significant capital expenditures. 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 Appalachian region. Pressure pumping services consist primarily of well stimulation services (such as hydraulic fracturing) and cementing services for completion of new wells and remedial work on existing wells. As of December 31, 2015, we had approximately 1.1 million hydraulic horsepower to provide these services. Our pressure pumping operations are supported by a fleet of other equipment, including blenders, tractors, manifold trailers and numerous trailers for transportation of materials to and from the worksite as well as bins for storage of materials at the worksite.

We also own and invest in oil and natural gas assets as a non-operating working interest owner. Our oil and natural gas working interests are located primarily in Texas and New Mexico.

Recent Developments

Oil prices have significantly declined since the second half of 2014. The closing price of oil, which was as high as $105.68 per barrel during the third quarter of 2014, reached a low price for 2015 of $34.55 in December 2015 and reached a twelve-year low of $26.68 in January 2016. As a result of the prolonged decline in oil prices, our industry continues to experience a severe decline in both contract drilling and pressure pumping activity levels. We do not expect this to change until commodity prices improve.

Low commodity prices are negatively impacting spending by exploration and production companies. The impact of these spending reductions is evidenced by published rig counts, which in the United States decreased more than 60% during 2015 and is now almost 70% lower than the peak in 2014.

Our rig count has also significantly declined. As of December 31, 2015, we had 80 drilling rigs operating in the United States, which was a decrease of 63% from the recent peak of 214 rigs in October 2014. Our operating rig count has continued to decline in 2016. On average, we operated 78 rigs in the United States during January 2016. Term contracts provided some support of our operating rig count during 2015. Based on contracts currently in place, we expect an average of 59 rigs operating under term contracts during the first quarter and an average of 46 rigs operating under term contracts during 2016.

Our pressure pumping business is continuing to experience the effects of reduced spending by customers and downward pressure on pricing. Due to market conditions, as of December 31, 2015, we had stacked approximately 38% of our fracturing horsepower. With the weakness in commodity prices since the beginning of 2016, we have seen a significant decrease in the amount of available work, and the profitability of available work has continued to deteriorate. In response, since the beginning of 2016, we have stacked approximately 140,000 fracturing horsepower. In total, we now have stacked slightly more than half of our fleet of more than 1 million hydraulic fracturing horsepower.

In anticipation of this downturn, we began reducing our cost structure in the fourth quarter of 2014. In 2015, we continued to reduce our cost structure and, to date, we have reduced our drilling headcount at a rate generally proportionate with the reduction in our rig count. In 2015, we significantly reduced our pressure pumping headcount and obtained lower prices on many products and services that we use. We also reduced our capital expenditures in 2015, and we expect our capital expenditures for 2016 to primarily consist of maintenance capital, inspections and potential upgrades, as we do not expect to build any new rigs or purchase any new fracturing horsepower in 2016. We plan to continue to adjust our cost structure in line with our level of operating activity.

We expect that our term contract coverage in contract drilling and scalability with respect to labor and other operating costs in contract drilling and pressure pumping should position us to weather this downturn. In the event oil prices remain depressed for a sustained period, or decline further, we may experience further significant declines in both drilling activity and spot dayrate pricing and in pressure pumping activity, which could have a material adverse effect on our business, financial condition and results of operations.

Industry Segments

Our revenues, operating profits and identifiable assets are primarily attributable to three industry segments:

- contract drilling services,
- pressure pumping services, and
- oil and natural gas exploration and production.

All of our industry segments had operating profits in 2013. In 2014, our contract drilling services and our pressure pumping services segments had operating profits and our oil and natural gas exploration and production segment had an operating loss. Our oil and natural gas assets constituted approximately 1% of our consolidated assets as of December 31, 2014. All of our industry segments had operating losses in 2015.

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

Contract Drilling Operations

General — We market our contract drilling services to major, independent and other oil and natural gas operators. As of December 31, 2015, we had 221 marketable land-based drilling rigs based in the following regions:

- 46 in west Texas and southeastern New Mexico,
- 17 in north central and east Texas and northern Louisiana
- 36 in the Rocky Mountain region (Colorado, Wyoming and North Dakota),
- 37 in south Texas,
- 29 in western Oklahoma,
- 45 in the Appalachian region (Pennsylvania, Ohio and West Virginia), and
- 11 in western Canada.

Our marketable drilling rigs have rated maximum depth capabilities ranging from approximately 10,000 feet to 25,000 feet. Of these drilling rigs, 202 are electric rigs and 19 are mechanical rigs. An electric rig differs from a mechanical rig in that the electric rig converts the power from its diesel engines (the sole energy source for a mechanical rig) 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 marketable 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 to ensure that our drilling equipment is competitive. We have spent over $1.8 billion 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 2015, 2014 and 2013, we spent approximately $527 million, $772 million and $505 million, respectively, on these capital expenditures.

Depth and complexity of the well and drill site conditions are the principal factors in determining the specifications of the rig selected for a particular job.

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

Drilling Contracts — Most of our drilling contracts are with established customers on a competitive bid or negotiated basis. Our bid for each job depends upon location, equipment to be used, estimated risks involved, estimated duration of the job, availability of drilling rigs and other factors particular to each proposed contract. Our drilling contracts are either on a well-to-well basis or a term basis. Well-to-well contracts are generally short-term in nature and cover the drilling of a single well or a series of wells. Term contracts are entered into for a specified period of time (frequently six months to three years) and provide for the use of the drilling rig to drill multiple wells. During 2015, our average number of days to drill a well (which includes moving to the drill site, rigging up and rigging down) was approximately 17 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. We believe that our drilling contracts generally provide for indemnification rights and obligations that are customary for the markets in which we conduct those operations. However, each drilling contract contains the actual terms setting forth our rights and obligations and those of the customer, any of which rights and obligations may deviate from what is customary due to particular industry conditions, customer requirements or other factors.

Our drilling contracts provide for payment on a daywork basis. Under daywork contracts, we provide the drilling rig and crew to the customer. The customer provides the program for the drilling of the well. Our compensation is based on a contracted rate per day during the period the drilling rig is utilized. We often receive a lower rate when the drilling rig is moving or when drilling operations are interrupted or restricted by adverse weather conditions or other conditions beyond our control. Daywork contracts typically provide separately for mobilization of the drilling rig. All of the wells we drilled in 2015, 2014 and 2013 were under daywork contracts.

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

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

	Year Ended December 31,		
	2015	2014	2013
Average rigs operating per day(1)	124	211	192
Number of rigs operated during the year	223	231	235
Number of wells drilled during the year	2,448	3,740	3,378
Number of operating days	45,142	77,000	69,918

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

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

To address our customers' needs for drilling horizontal wells in shale and other unconventional resource plays, we have expanded our areas of operation and improved the capability of our drilling fleet. We have delivered new APEX® rigs to the market and have made performance and safety improvements to existing high capacity rigs. APEX 1500® rigs are 1,500 horsepower electric rigs with advanced electronic drilling systems, 500 ton top drives, iron roughnecks, hydraulic catwalks, and other highly automated pipe handling equipment. APEX 1000® rigs are 1,000 horsepower electric rigs with advanced technology equipment similar to the APEX 1500® rigs, but with a more compact design to fit on smaller locations. APEX WALKING® rigs 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. Many APEX 1500® and APEX 1000® rigs have also been equipped with walking systems as noted below. As of December 31, 2015, our drilling fleet was comprised of the following:

	Number of Rigs			
Classification	United States	Canada	Total	Percent With Walking Systems
APEX 1500 rigs	96	1	97	62 %
APEX 1000 rigs	15	—	15	60 %
APEX WALKING rigs	49	—	49	100 %
Other electric rigs	35	6	41	12 %
Total electric rigs	195	7	202	61 %
Mechanical rigs	15	4	19	
Total	210	11	221	

	Number of Rigs		
Horsepower	United States	Canada	Total
2,000 to 2,500	12	—	12
1,500	133	1	134
1,000 to 1,400	61	5	66
750 to 950	4	5	9
Total	210	11	221
Average horsepower	1,386	1,068	1,370
Average depth rating	18,700	14,550	18,493

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

Pressure Pumping Operations

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

Pressure Pumping Contracts – Our pressure pumping operations are conducted pursuant to a work order for a specific job or pursuant to a term contract. The term contracts are generally entered into for a specified period of time and may include minimum revenue, usage or stage requirements. We are compensated based on a combination of charges for equipment, personnel, materials, mobilization and other items. We believe that our pressure pumping contracts generally provide for indemnification rights and obligations that are customary for the markets in which we conduct those operations. However, each pressure pumping contract contains the actual terms setting forth our rights and obligations and those of the customer, any of which rights and obligations may deviate from what is customary due to particular industry conditions, customer requirements or other factors.

Equipment — We have pressure pumping equipment used in providing hydraulic and nitrogen fracturing services as well as nitrogen, cementing and acid pumping services, with a total of approximately 1.1 million hydraulic horsepower as of December 31, 2015. Pressure pumping equipment at December 31, 2015 included:

	Hydraulic Fracturing Equipment	Other Pumping Equipment	Total
Southwest Region:			
Number of units	285	32	317
Approximate hydraulic horsepower	663,800	32,165	695,965
Northeast Region:			
Number of units	169	94	263
Approximate hydraulic horsepower	353,800	55,400	409,200
Combined:			
Number of units	454	126	580
Approximate hydraulic horsepower	1,017,600	87,565	1,105,165

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

Materials – Our pressure pumping operations require the use of acids, chemicals, proppants, fluid supplies and other materials, any of which can be in short supply, including severe shortages, from time to time. We purchase these materials from various suppliers. These purchases are made in the spot market or pursuant to other arrangements that do not cover all of our required supply and that 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.

Oil and Natural Gas Interests

We own and invest in oil and natural gas assets as a non-operating working interest owner. Our oil and natural gas working interests are located primarily in producing regions of Texas and New Mexico. Our oil and natural gas assets constituted less than 1% of our consolidated assets as of December 31, 2015.

Customers

Our customer base includes major, independent and other oil and natural gas operators. With respect to our consolidated operating revenues in 2015, we received approximately 49% from our ten largest customers and approximately 33% from our five largest customers. During 2015, one customer accounted for approximately $244 million, or approximately 13%, of our consolidated operating revenues. These revenues were earned in both our contract drilling and pressure pumping businesses. 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.

Competition

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

Government and Environmental Regulation

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

- drilling of oil and natural gas wells,
- hydraulic fracturing, cementing, nitrogen and acidizing and related well servicing activities,

- containment and disposal of hazardous materials, oilfield waste, other waste materials and acids,
- use of underground storage tanks and injection wells, and
- our employees.

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

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

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 by Congress under both CERCLA and RCRA may be deleted, limited, or modified in the future. If such changes are made to CERCLA and/or RCRA, we could be required to remove and remediate previously disposed of materials (including materials disposed of or released by prior owners or operators) from properties (including ground water contaminated with hydrocarbons) and to perform removal or remedial actions to prevent future contamination.

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

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

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

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

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

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

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

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

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

Risks and Insurance

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

We have indemnification agreements with many of our customers, and we also maintain liability and other forms of insurance. In general, our drilling and pressure pumping 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 drilling rigs, pressure pumping 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 drilling rigs and pressure pumping equipment and certain other assets, such insurance does not cover the full replacement cost of such drilling rigs, pressure pumping equipment or other assets. We have also elected in some cases to accept a greater amount of risk through increased deductibles on certain insurance policies. For example, we generally maintain a $1.5 million per occurrence deductible on our workers' compensation insurance coverage, a $1.0 million per occurrence deductible on our equipment insurance coverage, a $2.0 million per occurrence self-insured retention on our general liability coverage and a $2.0 million per occurrence deductible on our automobile liability insurance coverage. We self-insure a number of other risks, including loss of earnings and business interruption, and we do not carry a significant amount of insurance to cover risks of underground reservoir damage.

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

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

Employees

We had approximately 3,400 full-time employees as of February 4, 2016. The number of employees fluctuates depending on the current and expected demand for our services. We consider our employee relations to be satisfactory. None of our employees are represented by a union.

Seasonality

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

Raw Materials and Subcontractors

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

Item 1A. Risk Factors.

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

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

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

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

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

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

All of these factors are beyond our control. Oil prices have significantly declined since the second half of 2014. The closing price of oil, which was as high as $105.68 per barrel during the third quarter of 2014, reached a low price for 2015 of $34.55 in December 2015 and reached a twelve-year low of $26.68 in January 2016. As a result of the prolonged decline in oil prices, our industry continues to experience a severe decline in both contract drilling and pressure pumping activity levels. We do not expect this to change until commodity prices improve. Currently, our average number of rigs operating remains well below the number of our available rigs, and a significant portion of our fracturing horsepower is stacked.

We expect oil and natural gas prices to continue to be volatile and to affect our financial condition, operations and ability to access sources of capital. Higher oil and natural gas prices do not necessarily result in increased activity because demand for our services is generally driven by our customers' expectations of future oil and natural gas prices. A continued decline in demand for oil and natural gas or prolonged low oil or natural gas prices would likely result in further reduced capital expenditures by our customers and decreased demand for our drilling rigs and pressure pumping services, which could have a material adverse effect on our operating results, financial condition and cash flows.

Global Economic Conditions May Adversely Affect Our Operating Results.

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

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

The North American land drilling and pressure pumping businesses are highly competitive, and at times available land drilling rigs and pressure pumping equipment exceed the demand for such equipment. A low commodity price environment, such as the current environment, can result in substantially more drilling rigs and pressure pumping equipment being available than are needed to meet demand. In addition, in recent years there has been a substantial increase in the construction of new technology drilling rigs and new pressure pumping equipment. Low commodity prices and construction of new 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 an excess of equipment. High competition and excess equipment can cause drilling and pressure pumping contractors to have difficulty maintaining utilization and profit margins and, at times, result in operating losses. We cannot predict the future level of competition or excess equipment in the oil and natural gas contract drilling or pressure pumping businesses or the level of demand for our contract drilling or pressure pumping services.

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

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

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

We have indemnification agreements with many of our customers, and we also maintain liability and other forms of insurance. In general, our drilling and pressure pumping 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 drilling rigs, pressure pumping 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 drilling rigs and pressure pumping equipment and certain other assets, such insurance does not cover the full replacement cost of such drilling rigs, pressure pumping 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 and a $2.0 million per occurrence self-insured retention on our general liability coverage, a $2.0 million per occurrence deductible on our automobile liability insurance coverage. We self-insure a number of other risks, including loss of earnings and business interruption, and we do not carry a significant amount of insurance to cover risks of underground reservoir damage.

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

If a significant accident or other event occurs that is not fully covered by insurance or an enforceable and recoverable indemnity from a third party, it could have a material adverse effect on our business, financial condition, cash flows and results of operations.

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

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, 2015, 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 $710 million. Our contract drilling backlog may continue to decline as fixed-term, drilling contract coverage over time may not be offset by new contracts, including as a result of the decline in the price of oil and natural gas, capital spending reductions by our customers or other factors.

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

The market for our services is characterized by continual technological and process developments that have resulted in, and will likely continue to result in, substantial improvements in the functionality and performance of drilling rigs and equipment. Our customers are increasingly demanding the services of newer, higher specification drilling rigs. Accordingly, a higher level of capital expenditures may be required to maintain and improve existing rigs and equipment and purchase and construct newer, higher specification drilling rigs to meet the increasingly sophisticated needs of our customers. In addition, technological changes, process improvements and other factors that increase operational efficiencies could 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 business could have similar effects.

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

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

Shortages, Delays in Delivery and Interruptions in Supply of Drill Pipe, Replacement Parts, Other Equipment, Supplies and Materials Could Adversely Affect Our Operating Results.

During periods of increased demand for drilling and pressure pumping services, the industry has experienced shortages of drill pipe, replacement parts, other equipment, supplies 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, supplies 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 construct and operate our drilling rigs and pressure pumping equipment and could have a material adverse effect on our business, financial condition, cash flows and results of operations.

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

We greatly depend on the efforts of our key employees to manage our operations. The loss of members of management could have a material adverse effect on our business. In addition, we utilize highly skilled personnel in operating and supporting our businesses. In times of increasing demand for our services, it may be difficult to attract and retain qualified personnel. 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. 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 2015, we received approximately 49% from our ten largest customers, 33% from our five largest customers and 13% from our largest customer. The loss of, or reduction in business from, one or more of our larger customers could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Growth Through the Building of New Rigs and Pressure Pumping Equipment and Rig and Other Acquisitions Are Not Assured.

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

There can be no assurance that we will:

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

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

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

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

- substantial civil, criminal and/or administrative penalties,

- modification, denial or revocation of permits or other authorizations,
- imposition of limitations on our operations, and
- performance of site investigatory, remedial or other corrective actions.

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

Changes in environmental laws and regulations occur frequently and such laws and regulations tend to become more stringent over time. Stricter laws, regulations or enforcement policies could significantly increase compliance costs for us and our customers and have a material adverse effect on our operations or financial position. For example, on August 16, 2012, the EPA issued final rules that establish new air emission control requirements for natural gas and NGL production, processing and transportation activities, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds and National Emissions Standards for Hazardous Air Pollutants (“NESHAPS”) to address hazardous air pollutants frequently associated with gas production and processing activities. Among other things, these final rules require the reduction of volatile organic compound emissions from natural gas wells through the use of reduced emission completions or “green completions” on all hydraulically fractured wells constructed or refractured after January 1, 2015. In addition, gas wells are now required to use completion combustion device equipment (i.e., flaring) if emissions cannot be directed to a gathering line. Further, the final rules under NESHAPS include Maximum Achievable Control Technology standards for “small” glycol dehydrators that are located at major sources of hazardous air pollutants and modifications to the leak detection standards for valves. In December 2014, the EPA finalized amendments to these rules that distinguished between multiple flowback stages during completion and clarified that storage tanks permanently removed from service are not affected by any requirements. Then in July 2015, the EPA finalized two updates to the rules addressing the definition of low pressure gas wells and references to tanks that are connected to one another (referred to as connected in parallel). These rules may require the implementation of new operating standards which may impact our business. In September 2015, the EPA published a proposed rule that would update and expand the New Source Performance Standards by setting additional emissions limits for volatile organic compounds and regulating methane emissions for new and modified sources in the oil and gas industry. The EPA also published a proposed rule in September 2015 concerning aggregation of sources that would affect source determinations for air permitting in the oil and gas industry. If these or other initiatives result in an increase in regulation, it could increase costs to us and our customers or reduce demand for our services, which could have a material adverse effect on our business, financial condition, cash flows and results of operations.

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

Members of the U.S. Congress and the EPA are reviewing proposals for more stringent regulation of hydraulic fracturing, a technology employed by our pressure pumping business, which involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production. For example, the EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. As part of this study, the EPA sent requests to a number of companies, including our company, for information on hydraulic fracturing practices. We have responded to the inquiry. The EPA released a progress report in December 2012 outlining work currently underway and released a draft assessment report in June 2015. The draft assessment report concluded that activities have not led to widespread systematic impacts on drinking water resources in the United States, but there are above and below ground mechanisms by which hydraulic fracturing could affect drinking water resources. Further, we conduct drilling and pressure pumping 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. 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 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 adopted, could establish an additional level of regulation at the federal or state level that could limit or delay operational activities or increase operating costs and could result in additional regulatory burdens that could make it more difficult to perform or limit hydraulic fracturing and increase our costs of compliance and doing business.

Regulatory efforts at the federal level and in many states have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. The EPA has asserted federal regulatory authority over hydraulic fracturing using fluids that contain “diesel fuel” under the SDWA Underground Injection Control Program and has released a revised guidance regarding the process for obtaining a permit for hydraulic fracturing involving diesel fuel. In May 2014, the EPA issued an

Advanced Notice of Proposed Rulemaking, seeking comment on the development of regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. Further, in March 2015, the Bureau of Land Management ("BLM") issued a final rule to regulate hydraulic fracturing on Indian land. The rule requires companies to publicly disclose chemicals used in hydraulic fracturing operations to the BLM. However, in September 2015, the U.S. District Court of Wyoming granted a preliminary injunction temporarily preventing enforcement of the rule. A final decision is pending. In April 2015, the EPA published proposed 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, North Dakota, Montana, Texas, Louisiana, 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.

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

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

Legislation and Regulation of Greenhouse Gases Could Adversely Affect Our Business

We are aware of the increasing focus of local, state, regional, national and international regulatory bodies on GHG emissions and climate change issues. Legislation to regulate GHG emissions has periodically been introduced in the U.S. Congress, and there has been a wide-ranging policy debate, both in the United States and internationally, regarding the impact of these gases and possible means for their regulation. Some of the proposals would require industries to meet stringent new standards that would require substantial reductions in carbon emissions. Those reductions could be costly and difficult to implement. The EPA has adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources on an annual basis. Further, following a finding by the EPA that certain GHGs represent an endangerment to human health, the EPA finalized a rule to address permitting of GHG emissions from stationary sources under the Clean Air Act's New Source Review Prevention of Significant Deterioration ("PSD") and Title V programs. This final rule "tailors" the PSD and Title V programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. However, in June 2014, the U.S. Supreme Court in UARG v. EPA limited application of this rule to sources that would otherwise need permits based on emission of conventional pollutants. In April 2015, the D.C. Circuit Court of Appeals narrowed the rule in accordance with the Supreme Court's decision. In 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. The Paris Agreement will be open for signing in April 2016 and will require countries to review and "represent a progression" in their intended nationally determined contributions, which set emissions reduction goals, every five years, beginning in 2020. Several states and geographic regions in the United States have also adopted legislation and regulations to reduce emissions of GHGs. Additional legislation or regulation by these states and regions, the EPA, and/or any international agreements to which the United States may become a party, that control or limit GHG emissions or otherwise seek to address climate change could adversely affect our operations. The cost of complying with any new law, regulation or treaty will depend on the details of the particular program. We will continue to monitor and assess any new policies, legislation or regulations in the areas where we operate to determine the impact of GHG emissions and climate change on our operations and take appropriate actions, where necessary. Any direct and indirect costs of meeting these requirements may adversely affect our business, results of operations and financial condition. Because our business depends on the level of activity in the oil and natural gas industry, existing or future laws or regulations related to GHGs and climate change, including incentives to conserve energy or use alternative energy sources, could have a negative impact on our business if such laws or regulations reduce demand for oil and natural gas.

Legal Proceedings Could Have a Negative Impact on our Business.

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, such as the one we are currently experiencing, 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.

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. 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 of the parts of the world where contract drilling and pressure pumping activities are conducted have experienced governmental corruption to some degree and, in certain circumstances, strict compliance with anti-bribery laws may conflict with local customs and practice and could impact business. Any failure to comply with the FCPA or other anti-bribery legislation could subject to us to civil, criminal and/or administrative penalties or other sanctions, which could have a material adverse impact on our business, financial condition and results of operation. We could also face fines, sanctions and other penalties from authorities in the relevant foreign jurisdictions, including prohibition of our participating in or curtailment of business operations in those jurisdictions and the seizure of drilling rigs, pressure pumping equipment or other assets.

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

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

Our Business Is Subject to Cybersecurity Risks and Threats.

Threats to information technology systems associated with cybersecurity risks and cyber incidents or attacks continue to grow. It is possible that our business, financial and other systems could be compromised, which might not be noticed for some period of time. Risks associated with these threats include, among other things, loss of intellectual property, disruption of our and customers' business operations and safety procedures, loss or damage to our worksite data delivery systems, unauthorized disclosure of personal information, and increased costs to prevent, respond to or mitigate cybersecurity events.

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

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

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

We have in place a committed senior unsecured credit facility that includes a revolving credit facility and a term loan 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 margin on LIBOR loans ranges from 2.25% to 3.25% and the margin on base rate loans ranges from 1.25% to 2.25%, based on our debt to capitalization ratio. At December 31, 2015, the margin on LIBOR loans was 2.25% and the margin on base rate loans was 1.25%. Based on our debt to capitalization ratio at December 31, 2015, the applicable margin on LIBOR loans will be 2.75% and the applicable margin on base rate loans will be 1.75% as of April 1, 2016. As of December 31, 2015, we had no amounts outstanding under our revolving credit facility and $70.0 million outstanding under our term credit facility at an interest rate of 2.875%. A one percent increase in the interest rate on the borrowings outstanding under our revolving credit facility and term credit facility as of December 31, 2015 would increase our annual cash interest expense by approximately $632,000.

We have in place a term loan agreement which bears interest, at our election, at the per annum rate of LIBOR plus 3.25% or base rate plus 2.25%. As of December 31, 2015, we had $185 million outstanding under the term loan agreement at an interest rate of 3.875%. A one percent increase in the interest rate on the borrowings outstanding under the term loan agreement as of December 31, 2015 would increase our annual cash interest expense by approximately $1.8 million.

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, 2015, 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.

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.

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 450 Gears Road, Suite 500, Houston, Texas. Our telephone number at that address is (281) 765-7100. Our primary administrative office, which is located in Snyder, Texas, is owned and includes approximately 37,000 square feet of office and storage space.

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

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

Oil and Natural Gas Working Interests — 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 of our 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 3 of the Notes to Consolidated Financial Statements included in Item 8 of this Report.

Item 3. Legal Proceedings.

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

Item 4. Mine Safety Disclosure.

Not applicable.

PART II

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

(a) Market Information

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

	High	Low
2014:		
First quarter	$31.95	$24.37

Second quarter	35.42	30.24
Third quarter	38.43	31.12
Fourth quarter	33.28	14.01
2015:		
First quarter	$19.70	$13.30
Second quarter	23.11	18.30
Third quarter	18.80	12.97
Fourth quarter	17.45	12.82

(b) Holders

As of February 4, 2016, there were approximately 1,300 holders of record of our common stock.

(c) Dividends

We paid cash dividends during the years ended December 31, 2014 and 2015 as follows:

	Per Share	Total (in thousands)
2014:		
Paid on March 27, 2014	$ 0.10	$ 14,456
Paid on June 26, 2014	0.10	14,562
Paid on September 24, 2014	0.10	14,634
Paid on December 24, 2014	0.10	14,636
Total cash dividends	$ 0.40	$ 58,288
2015:		
Paid on March 25, 2015	$ 0.10	$ 14,640
Paid on June 24, 2015	0.10	14,712
Paid on September 24, 2015	0.10	14,712
Paid on December 24, 2015	0.10	14,711
Total cash dividends	$ 0.40	$ 58,775

On February 3, 2016, our Board of Directors approved a cash dividend on our common stock in the amount of $0.10 per share to be paid on March 24, 2016 to holders of record as of March 10, 2016. Our 2015 Term Loan Agreement contains a covenant that could restrict our ability to make dividend payments later in 2016. This covenant applies to only the 2015 Term Loan Agreement indebtedness, and we believe that our strong financial position allows us various alternatives to address this restriction, including repayment of this debt. However, 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.

(e) 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, 2015.

Period Covered	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares (or Units) Purchased	Approximate Dollar Value of Shares That May Yet Be Purchased

				as Part of Publicly Announced Plans or Programs	Under the Plans or Programs (in thousands)(1)
October 2015	—	$	—	—	$ 186,836
November 2015	—	$	—	—	$ 186,836
December 2015	—	$	—	—	$ 186,836
Total	—	$	—	—	$ 186,836

(1) On September 9, 2013, we announced that our Board of Directors approved a stock buyback program authorizing purchases of up to $200 million of our common stock in open market or privately negotiated transactions.

(e) Performance Graph

The following graph compares the cumulative stockholder return of our common stock for the period from December 31, 2010 through December 31, 2015, with the cumulative total return of the Standard & Poors 500 Stock Index, the Standard & Poors MidCap Index, the Oilfield Service Index and a peer group determined by us. Our peer group consists of Helmerich & Payne, Inc., Nabors Industries, Ltd., Pioneer Energy Services Corp. and Precision Drilling Corp. All of the companies in our peer group are providers of land-based drilling services. Nabors Industries, Ltd. also has a majority equity interest in C&J Energy Services Ltd., which has a pressure pumping business. The graph assumes investment of $100 on December 31, 2010 and reinvestment of all dividends.

	Fiscal Year Ended December 31,					
	2010	2011	2012	2013	2014	2015
Company/Index	($)	($)	($)	($)	($)	($)
Patterson-UTI Energy, Inc.	100.00	93.49	88.24	121.02	80.57	75.02
Peer Group Index	100.00	96.88	85.44	114.23	89.19	67.10
S&P 500 Stock Index	100.00	102.11	118.45	156.82	178.28	180.75
Oilfield Service Index	100.00	89.45	92.29	119.59	91.44	70.06
S&P MidCap Index	100.00	98.27	115.84	154.64	169.75	166.06

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, 2015, 2014, 2013, 2012 and 2011, and for each of the five years in the period ended December 31, 2015 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. Due to the sale of our electric wireline business in January 2011, the results of operations for that business have been reclassified and are presented as discontinued operations for all periods presented.

	Years Ended December 31,				
	2015	2014	2013	2012	2011
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Operating revenues:					
Contract drilling	$1,153,892	$1,838,830	$1,679,611	$1,821,713	$1,669,581
Pressure pumping	712,454	1,293,265	979,166	841,771	845,803
Oil and natural gas	24,931	50,196	57,257	59,930	50,559
Total	1,891,277	3,182,291	2,716,034	2,723,414	2,565,943
Operating costs and expenses:					
Contract drilling	608,848	1,066,659	968,754	1,075,491	972,778
Pressure pumping	612,021	1,036,310	744,243	580,878	561,398
Oil and natural gas	11,500	13,102	12,909	11,303	9,615
Depreciation, depletion, amortization and impairment	864,759	718,730	597,469	526,614	437,279
Impairment of goodwill	124,561	-	-	-	-
Selling, general and administrative	87,173	80,145	73,852	64,473	64,271
Net gain on asset disposals	(10,613)	(15,781)	(3,384)	(33,806)	(4,999)
Provision for bad debts	—	—	—	1,100	—
Total	2,298,249	2,899,165	2,393,843	2,226,053	2,040,342
Operating income (loss)	(406,972)	283,126	322,191	497,361	525,601
Other expense	(35,477)	(28,843)	(25,750)	(21,688)	(14,883)
Income (loss) from continuing operations before income taxes	(442,449)	254,283	296,441	475,673	510,718
Income tax expense (benefit)	(147,963)	91,619	108,432	176,196	187,938
Income (loss) from continuing operations	$(294,486)	$162,664	$188,009	$299,477	$322,780
Income (loss) from continuing operations per common share:					
Basic	$(2.00)	$1.12	$1.29	$1.96	$2.08
Diluted	$(2.00)	$1.11	$1.28	$1.96	$2.06
Cash dividends per common share	$0.40	$0.40	$0.20	$0.20	$0.20
Weighted average number of common shares outstanding:					
Basic	145,416	144,066	144,356	151,144	153,871
Diluted	145,416	145,376	145,303	151,699	155,304
Balance Sheet Data:					

Total assets	$4,533,317	$5,394,011	$4,687,127	$4,556,911	$4,221,901
Borrowings under line of credit	—	303,000	—	—	110,000
Other long-term debt	791,250	670,000	682,500	692,500	382,500
Stockholders' equity	2,561,131	2,905,810	2,755,997	2,640,657	2,516,631
Working capital	178,404	340,688	454,373	340,128	346,238

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

Recent Developments — Oil prices have significantly declined since the second half of 2014. The closing price of oil, which was as high as $105.68 per barrel during the third quarter of 2014, reached a low price for 2015 of $34.55 in December 2015 and reached a twelve-year low of $26.68 in January 2016. As a result of the prolonged decline in oil prices, our industry continues to experience a severe decline in both contract drilling and pressure pumping activity levels. We do not expect this to change until commodity prices improve.

Low commodity prices are negatively impacting spending by exploration and production companies. The impact of these spending reductions is evidenced by published rig counts, which in the United States decreased more than 60% during 2015 and is now almost 70% lower than the peak in 2014.

Our rig count has also significantly declined. As of December 31, 2015, we had 80 drilling rigs operating in the United States, which was a decrease of 63% from the recent peak of 214 rigs in October 2014. Our operating rig count has continued to decline in 2016. On average, we operated 78 rigs in the United States during January 2016. Term contracts provided some support of our operating rig count during 2015. Based on contracts currently in place, we expect an average of 59 rigs operating under term contracts during the first quarter and an average of 46 rigs operating under term contracts during 2016.

Our pressure pumping business is continuing to experience the effects of reduced spending by customers and downward pressure on pricing. Due to market conditions, as of December 31, 2015, we had stacked approximately 38% of our fracturing horsepower. With the weakness in commodity prices since the beginning of 2016, we have seen a significant decrease in the amount of available work, and the profitability of available work has continued to deteriorate. In response, since the beginning of 2016, we have stacked approximately 140,000 fracturing horsepower. In total, we now have stacked slightly more than half of our fleet of more than 1 million hydraulic fracturing horsepower.

In anticipation of this downturn, we began reducing our cost structure in the fourth quarter of 2014. In 2015, we continued to reduce our cost structure and, to date, we have reduced our drilling headcount at a rate generally proportionate with the reduction in our rig count. In 2015, we significantly reduced our pressure pumping headcount and obtained lower prices on many products and services that we use. We also reduced our capital expenditures in 2015, and we expect our capital expenditures for 2016 to primarily consist of maintenance capital, inspections and potential upgrades, as we do not expect to build any new rigs or purchase any new fracturing horsepower in 2016. We plan to continue to adjust our cost structure in line with our level of operating activity.

We expect that our term contract coverage in contract drilling and scalability with respect to labor and other operating costs in contract drilling and pressure pumping should position us to weather this downturn. In the event oil prices remain depressed for a sustained period, or decline further, we may experience further significant declines in both drilling activity and spot dayrate pricing and in pressure pumping activity, which could have a material adverse effect on our business, financial condition and results of operations.

Management Overview — We are a leading provider of services to the North American oil and natural gas industry. Our services primarily involve the drilling, on a contract basis, of land-based oil and natural gas wells and pressure pumping services. In addition to these services, we also invest, on a non-operating working interest basis, in oil and natural gas properties.

We operate land-based drilling rigs in oil and natural gas producing regions of the continental United States and western Canada, and we are pursuing contract drilling opportunities outside of North America. There continues to be uncertainty with respect to the global economic environment, and oil and natural gas prices are significantly depressed. During the fourth quarter of 2015, our average number of rigs operating in the United States was 88 compared to an average of 210 drilling rigs operating during the same period in 2014. During the fourth quarter of 2015, our average number of rigs operating in Canada was three compared to an average of nine drilling rigs operating during the fourth quarter of 2014.

We have addressed our customers' needs for drilling horizontal wells in shale and other unconventional resource plays by expanding our areas of operation and improving the capabilities of our drilling fleet during the last several years. As of December 31, 2015, our rig fleet included 161 APEX® rigs. We do not expect to add any new rigs to our fleet during 2016.

In connection with the development of horizontal shale and other unconventional resource plays, we have added equipment to perform service intensive fracturing jobs. As of December 31, 2015, we had approximately 1.1 million hydraulic horsepower in our pressure pumping fleet. We have increased the horsepower of our pressure pumping fleet by more than eight-fold since the beginning of 2009, although we have not ordered or committed to purchase any new horsepower since October 2014 and there is currently no new horsepower on order. In recent years, the industry-wide addition of new pressure pumping equipment to the marketplace and lower oil and natural gas prices have led to an excess supply of pressure pumping equipment in North America.

We maintain a backlog of commitments for contract drilling revenues under term contracts, which we define as contracts with a fixed term of six months or more. Our contract drilling backlog as of December 31, 2015 and 2014 was $710 million and $1.5 billion, respectively. The decrease in backlog at December 31, 2015 from December 31, 2014, is primarily due to the revenue earned since December 31, 2014, including from the receipt of early termination payments, and the expiration and termination of term contracts. Approximately 40 percent of the total December 31, 2015 backlog is reasonably expected to remain after 2016. We generally calculate our backlog by multiplying the dayrate under our term drilling contracts by the number of days remaining under the contract. The calculation does not include any revenues related to other fees such as for mobilization, demobilization and customer reimbursables, nor does it include potential reductions in rates for unscheduled standby or during periods in which the rig is moving or incurring maintenance and repair time in excess of what is permitted under the drilling contract. In addition, generally our term drilling contracts are subject to termination by the customer on short notice and provide for an early termination payment to us in the event that the contract is terminated by the customer. For contracts that we have received an early termination notice, our backlog calculation includes the early termination rate, instead of the dayrate, for the period we expect to receive the lower rate. See "Item 1A. Risk Factors – Our Current Backlog of Contract Drilling Revenue May Continue to Decline and May Not Ultimately Be Realized, as Fixed-Term Contracts May in Certain Instances Be Terminated Without an Early Termination Payment."

For the three years ended December 31, 2015, our operating revenues consisted of the following (dollars in thousands):

	2015		2014		2013	
Contract drilling	$1,153,892	61 %	$1,838,830	58 %	$1,679,611	62 %
Pressure pumping	712,454	38 %	1,293,265	41 %	979,166	36 %
Oil and natural gas	24,931	1 %	50,196	1 %	57,257	2 %
	$1,891,277	100%	$3,182,291	100%	$2,716,034	100%

Generally, the profitability of our business is impacted most by two primary factors in our contract drilling segment: our average number of rigs operating and our average revenue per operating day. During 2015, our average number of rigs operating was 120 in the United States and four in Canada compared to 203 in the United States and eight in Canada in 2014 and 184 in the United States and eight in Canada in 2013. Our average rig revenue per operating day was $25,560 in 2015 compared to $23,880 in 2014 and $24,020 in 2013. We had a consolidated net loss of $294 million for 2015 compared to consolidated net income of $163 million for 2014. The financial results for 2015 include pretax non-cash charges totaling approximately $288 million. These charges include $125 million from the impairment of all goodwill associated with our pressure pumping business, $131 million from the write-down of drilling equipment primarily related to mechanical rigs and spare mechanical rig components, $22.0 from the write-down of pressure pumping equipment and closed facilities and $10.7 million related to the impairment of certain oil and natural gas properties. The financial results for 2014 include a pretax non-cash charge of $77.9 million related to the retirement of mechanical rigs and the write-off of excess spare components.

Our revenues, profitability and cash flows are highly dependent upon prevailing prices for oil and natural gas. During periods of improved commodity prices, the capital spending budgets of oil and natural gas operators tend to expand, which generally results in increased demand for our services. Conversely, in periods when these commodity prices deteriorate, the demand for our services generally weakens and we experience downward pressure on pricing for our services. Oil and natural gas prices and our monthly average number of rigs operating have significantly declined from recent highs. In December 2015, our average number of rigs operating was 82 in the United States. In January 2016, our average number of rigs operating decreased to 78 in the United States.

We are also highly impacted by operational risks, competition, the availability of excess equipment, labor issues, weather and various other factors that could materially adversely affect our business, financial condition, cash flows and results of operations. Please see "Risk Factors" in Item 1A of this Report.

Critical Accounting Policies

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

Property and equipment — Property and equipment, including betterments which extend the useful life of the asset, are stated at cost. Maintenance and repairs are charged to expense when incurred. We provide for the depreciation of our property and equipment using the straight-line method over the estimated useful lives. Our method of depreciation does not change when equipment becomes idle; we continue to depreciate idled equipment on a straight-line basis. No provision for salvage value is considered in determining depreciation of our property and equipment. We review our long-lived assets, including property and equipment, for impairment whenever events or changes in circumstances ("triggering events") indicate that the carrying values of certain assets may not be recovered over their estimated remaining useful lives. In connection with this review, assets are grouped at the lowest level at which identifiable cash flows are largely independent of other asset groupings. The cyclical nature of our industry has resulted in fluctuations in rig utilization over periods of time. Management believes that the contract drilling industry will continue to be cyclical and rig utilization will continue to fluctuate. Based on management's expectations of future trends, we estimate future cash flows over the life of the respective assets or asset groupings in our assessment of impairment. These estimates of cash flows are based on historical cyclical trends in the industry as well as management's expectations regarding the continuation of these trends in the future.

Provisions for asset impairment are charged against income when estimated future cash flows, on an undiscounted basis, are less than the asset's net book value. Any provision for impairment is measured at fair value.

On a periodic basis, we evaluate our fleet of drilling rigs for marketability based on the condition of inactive rigs, expenditures that would be necessary to bring them to working condition and the expected demand for drilling services by rig type (such as drilling conventional, vertical wells versus drilling longer, horizontal wells using higher specification rigs). The components comprising rigs that will no longer be marketed are evaluated, and those components with continuing utility to our other marketed rigs are transferred to other rigs or to our yards to be used as spare equipment. The remaining components of these rigs will be retired. In 2015, we identified 24 mechanical rigs and 9 non-APEX® electric rigs that would no longer be marketed. Also, we had 15 additional mechanical rigs that were not operating. Although these 15 rigs remain marketable, we have lower expectations with respect to utilization of these rigs due to the industry shift to higher specification drilling rigs. In 2015, we recorded a charge of $131 million related to the retirement of the 33 rigs, the 15 mechanical rigs that remain marketable but were not operating, and the write-down of excess spare rig components to their realizable values. In 2014, we identified 55 mechanical rigs that we determined would no longer be marketed, and we recorded a charge of $77.9 million related to the retirement of these mechanical rigs and the write-off of excess spare components for the reduced size of our mechanical fleet. In 2013, we identified 48 rigs that would no longer be marketed. Also, we had 55 additional mechanical rigs that were not operating. Although these 55 rigs remained marketable at the time, we had lower expectations with respect to utilization of these rigs due to the industry shift to electric powered drilling rigs. In 2013, we recorded a charge of $37.8 million related to the retirement of the 48 rigs and the 55 mechanical rigs that remained marketable but were not operating.

We also periodically evaluate our pressure pumping assets, and in 2015, we recorded a charge of $22.0 million for the write-down of pressure pumping equipment and certain closed facilities. There were no similar charges in 2014 or 2013.

We evaluate the recoverability of our long-lived assets whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable (a "triggering event"). During the first quarter of 2015, oil prices averaged $48.54 per barrel and reached a low of $43.39 per barrel in March 2015. Oil prices improved during the second quarter of 2015 and averaged $57.85 per barrel. Although the price improvement was earlier than we projected, this improvement was generally consistent with our assumption at December 31, 2014 that oil prices would improve late in 2015 and continue to improve in 2016, resulting in improved activity levels for both the contract drilling and pressure pumping businesses. During the second quarter of 2015 as oil prices increased, we received requests from customers to reactivate drilling rigs to resume operations in the third quarter of 2015. We believed this was an indication that future activity levels would be improving for both the contract drilling and pressure pumping businesses. During the third quarter of 2015, however, oil prices declined and averaged $46.42 per barrel and reached a new low for 2015 of $38.22 per barrel in August 2015.

With lower oil prices in August, we lowered our expectations with respect to future activity levels in both the contract drilling and pressure pumping businesses. In light of these revised expectations of the duration of the lower oil and natural gas commodity price environment and the related deterioration of the markets for contract drilling and pressure pumping services during the third quarter of 2015, we deemed it necessary to assess the recoverability of long-lived asset groups for both contract drilling and pressure pumping. We performed a Step 1 analysis as required by ASC 360-10-35 to assess the recoverability of long-lived assets within our contract drilling and pressure pumping segments. With respect to these assets, future cash flows were estimated over the expected remaining life of the assets, and we determined that, on an undiscounted basis, expected cash flows exceeded the carrying value of the long-lived assets, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the long-lived assets within the contract drilling and pressure pumping segments by approximately 120% and 60%, respectively.

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

For both of the assessments performed in 2015, the expected cash flows for the contract drilling segment included the backlog of commitments for contract drilling revenues under term contracts, which was approximately $801 million and $710 million at September 30, 2015 and December 31, 2015, respectively. Rigs not under term contracts will be subject to pricing in the spot market. Utilization and rates for rigs in the spot market and for the pressure pumping segment were estimated based upon our historical experience in prior downturns. Also, the expected cash flows for the contract drilling and pressure pumping segments were based on the assumption that activity levels in both segments would begin to recover in the first quarter of 2017 in response to improved oil prices. While we believe these assumptions with respect to future pricing for oil and natural gas are reasonable, actual future prices may vary significantly from the ones that were assumed. The timeframe over which oil and natural gas prices will 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:

- market supply and demand,

- the desire and ability of the Organization of Petroleum Exporting Countries, commonly known as OPEC, to set and maintain production and price targets,
- the level of production by OPEC and non-OPEC countries,
- domestic and international military, political, economic and weather conditions,
- legal and other limitations or restrictions on exportation and/or importation of oil and natural gas,
- technical advances affecting energy consumption and production,
- the price and availability of alternative fuels,
-

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

- regulations regarding the exploration, development, production and delivery of oil and natural gas.

All of these factors are beyond our control. If the current lower oil and natural gas commodity price environment were to last into 2017 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.

Goodwill — Goodwill is considered to have an indefinite useful economic life and is not amortized. Goodwill is evaluated at least annually as of December 31, or when circumstances require, to determine if the fair value of recorded goodwill has decreased below its carrying value. For purposes of impairment testing, goodwill is evaluated at the reporting unit level. Our reporting units for impairment testing have been determined to be our operating segments. We first 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 it is, then goodwill impairment is determined using a two-step quantitative impairment test. From time to time, we may perform the first step of the quantitative testing for goodwill impairment in lieu of performing the qualitative assessment. The first step of the quantitative testing is to compare the fair value of an entity's reporting units to the respective carrying value of those reporting units. If the carrying value of a reporting unit exceeds its fair value, the second step of the quantitative testing is performed whereby the fair value of the reporting unit is allocated to its identifiable tangible and intangible assets and liabilities with any remaining fair value representing the fair value of goodwill. If this resulting fair value of goodwill is less than the carrying value of goodwill, an impairment loss would be recognized in the amount of the shortfall.

During the first quarter of 2015, oil prices averaged $48.54 per barrel and reached a low of $43.39 per barrel in March 2015. Oil prices improved during the second quarter of 2015 and averaged $57.85 per barrel. Although the price improvement was earlier than we projected, this improvement was generally consistent with our assumption at December 31, 2014, that oil prices would improve in late 2015 and continue to improve in 2016, resulting in improved activity levels for both the contract drilling and pressure pumping businesses. During the second quarter of 2015 as oil prices increased, we received requests from customers to reactivate drilling rigs to resume operations in the third quarter of 2015. We believed this was an indication that future activity levels would be improving for both the contract drilling and pressure pumping businesses. During the third quarter of 2015, however, oil prices declined and averaged $46.42 per barrel and reached a new low for 2015 of $38.22 per barrel in August 24, 2015. With lower oil prices in August, we lowered our expectations with respect to future activity levels in both the contract drilling and pressure pumping businesses. In light of our revised expectations of the duration of the lower oil and natural gas commodity price environment and the related deterioration of the markets for contract drilling and pressure pumping services during the third quarter of 2015, we performed a quantitative impairment assessment of our goodwill as of September 30, 2015. In completing the first step of the assessment, the fair value of each reporting unit was estimated using both the income and market valuation methods. The estimate of the fair value of each reporting unit required the use of significant unobservable inputs, representative of a Level 3 fair value measurement. The inputs included assumptions related to the future performance of our contract drilling and pressure pumping reporting units, such as future oil and natural gas prices and projected demand for our services, and assumptions related to discount rates, long-term growth rates and control premiums.

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

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

In connection with our annual goodwill impairment assessment as of December 31, 2014, 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 their carrying amounts and further testing was not necessary. In making this determination, we considered the continued demand experienced during 2014 for our services in the contract drilling and pressure pumping businesses. We also considered the current and expected levels of commodity prices for oil and natural gas, which influence the overall level of business activity in these operating segments. Additionally, operating results for 2014 and forecasted operating results for 2015 were also taken into account. Our overall market capitalization and the large amount of calculated excess of the fair values of our reporting units over their carrying values from our 2013 quantitative Step 1 assessment of goodwill were also considered.

We have undertaken extensive efforts in the past several years to upgrade our fleet of equipment and believe that we are well positioned from a competitive standpoint to satisfy demand for high technology drilling of unconventional horizontal wells, which should help mitigate decreases in demand for drilling conventional vertical wells. In the event that market conditions were to remain weak for a protracted period, we may be required to record an impairment of goodwill in our contract drilling reporting unit in the future, and such impairment could be material.

Revenue recognition — Revenues from daywork drilling and pressure pumping activities are recognized as services are performed. Expenditures reimbursed by customers are recognized as revenue and the related expenses are recognized as direct costs. All of the wells we drilled in 2015, 2014 and 2013 were drilled under daywork contracts.

Use of 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 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.

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. We review 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, we consider the well costs to be impaired and recognize 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.

We review our 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 our 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 expected future net cash flows are discounted using an annual rate of 10% to determine fair value. We review unproved oil and natural gas properties quarterly to assess potential impairment. Our impairment assessment is made on a lease-by-lease basis and considers factors such as our 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 proved and unproved oil and natural gas properties totaled approximately $10.7 million, $20.9 million and $4.0 million for the years ended December 31, 2015, 2014 and 2013, respectively, and is included in depreciation, depletion, amortization and impairment in the consolidated statements of operations.

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.

Liquidity and Capital Resources

Our liquidity as of December 31, 2015 included approximately $178 million in working capital and $500 million available under our revolving credit facility.

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. If under current market conditions we desire to pursue opportunities for growth that require capital, we believe we would likely require 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, 2015, we had working capital of $178 million, including cash and cash equivalents of $113 million, compared to working capital of $341 million and cash and cash equivalents of $43 million at December 31, 2014.

During 2015, our sources of cash flow included:

- $999 million from operating activities,
- $200 million in borrowings pursuant to a new term loan agreement, and
- $20.8 million in proceeds from the disposal of property and equipment.

During 2015, we used a net of $303 million to pay off our revolving credit facility, $58.8 million to pay dividends on our common stock, $27.5 million to repay long-term debt, $8.0 million to acquire shares of our common stock, $2.0 million to pay debt issuance costs and $744 million:

- to build and to acquire components to build new drilling rigs and to purchase new pressure pumping equipment,
- to make capital expenditures for the betterment and refurbishment of existing drilling rigs and pressure pumping equipment,
- to acquire and procure equipment and facilities for our drilling and pressure pumping 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, 2015 as follows:

	Per Share	Total (in thousands)
Paid on March 25, 2015	$ 0.10	$ 14,640
Paid on June 24, 2015	0.10	14,712
Paid on September 24, 2015	0.10	14,712
Paid on December 24, 2015	0.10	14,711
Total cash dividends	$ 0.40	$ 58,775

On February 3, 2016, our Board of Directors approved a cash dividend on our common stock in the amount of $0.10 per share to be paid on March 24, 2016 to holders of record as of March 10, 2016. Our 2015 Term Loan Agreement contains a covenant that could restrict our ability to make dividend payments later in 2016. This covenant applies to only the 2015 Term Loan Agreement indebtedness, and we believe that our strong financial position allows us various alternatives to address this restriction, including repayment of this debt. However, 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 July 25, 2012, our Board of Directors approved a stock buyback program authorizing purchases of up to $150 million of our common stock in open market or privately negotiated transactions. On September 6, 2013, our Board of Directors terminated any remaining authority under the 2012 stock buyback program, and approved a new stock buyback program that authorizes purchase of up to $200 million of our common stock in open market or privately negotiated transactions. As of December 31, 2015, we had remaining authorization to purchase approximately $187 million of our outstanding common stock under the 2013 stock buyback program. Shares purchased under a buyback program are accounted for as treasury stock.

We acquired shares of stock from employees during 2015, 2014 and 2013 that are accounted for as treasury stock. Certain of these shares were acquired to satisfy the exercise price in connection with the exercise of stock options by employees. The remainder of these shares was acquired to satisfy payroll tax withholding obligations upon the exercise of stock options, the settlement of performance unit awards and the vesting of restricted stock. These shares were acquired at fair market value. These acquisitions were made pursuant to the terms of the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (the "2005 Plan") or the Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan (the "2014 Plan") and not pursuant to the stock buyback programs.

Treasury stock acquisitions during the year ended December 31, 2015, 2014 and 2013 were as follows (dollars in thousands):

	2015		2014		2013	
	Shares	Cost	Shares	Cost	Shares	Cost
Treasury shares at beginning of period	42,818,585	$899,035	42,268,057	$880,888	38,146,738	$795,051
Purchases pursuant to stock buyback programs:						
2012 program	—	—	—	—	2,567,266	51,107
2013 program	8,618	180	13,898	466	602,564	12,517
Acquisitions pursuant to long-term incentive plans	380,037	7,830	536,630	17,681	951,489	22,213
Treasury shares at end of period	43,207,240	$907,045	42,818,585	$899,035	42,268,057	$880,888

2012 Credit Agreement — On September 27, 2012, we entered into a credit agreement (the "Credit Agreement"). The Credit Agreement is a committed senior unsecured credit facility that includes a revolving credit facility and a term loan facility. The Credit Agreement replaced a previous senior unsecured revolving credit facility.

The revolving credit facility permits aggregate borrowings of up to $500 million outstanding at any time. The revolving credit facility contains a letter of credit facility that is limited to $150 million and a swing line facility that is limited to $40 million, in each case outstanding at any time.

The term loan facility provides for a loan of $100 million, which was drawn on December 24, 2012. The term loan facility is payable in quarterly principal installments which commenced December 27, 2012. The installment amounts vary from 1.25% of the original principal amount for each of the first four quarterly installments, 2.50% of the original principal amount for each of the subsequent eight quarterly installments, 5.00% of the original principal amount for the subsequent four quarterly installments and 13.75% of the original principal amount for the final four quarterly installments.

Subject to customary conditions, we may request that the lenders' aggregate commitments with respect to the revolving credit facility and/or the term loan facility be increased by up to $100 million, not to exceed total commitments of $700 million. The maturity date under the Credit Agreement is September 27, 2017 for both the revolving facility and the term facility.

Loans under the Credit Agreement bear interest by reference, at our election, to the LIBOR rate or base rate, provided, that swing line loans bear interest by reference only to the base rate. The applicable margin on LIBOR rate loans varies from 2.25% to 3.25% and the applicable margin on base rate loans varies from 1.25% to 2.25%, in each case determined based upon our debt to capitalization ratio. As of December 31, 2015, the applicable margin on LIBOR rate loans was 2.25% and the applicable margin on base rate loans was 1.25%. Based on our debt to capitalization ratio at September 30, 2015, the applicable margin on LIBOR rate loans is 2.25% and the applicable margin on base rate loans is 1.25% as of January 1, 2016. Based on our debt to capitalization ratio at December 31, 2015, the applicable margin on LIBOR rate loans will be 2.75% and the applicable margin on base rate loans will be 1.75% as of April 1, 2016. A letter of credit fee is payable by us equal to the applicable margin for LIBOR rate loans times the amount available to be drawn under outstanding letters of credit. The commitment fee rate payable to the lenders for the unused portion of the credit facility is 0.50%.

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

The Credit Agreement requires compliance with two financial covenants. We must not permit our debt to capitalization ratio to exceed 45%. The Credit Agreement generally defines the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. We also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 3.00 to 1.00. The Credit Agreement generally defines the interest coverage ratio as the ratio of earnings before interest, taxes, depreciation and amortization ("EBITDA") of the four prior fiscal quarters to interest charges for the same period. We were in compliance with these covenants at December 31, 2015. The Credit Agreement also contains customary representations, warranties and affirmative and negative covenants. We do not expect that the restrictions and covenants will impair, in any material respect, our ability to operate or react to opportunities that might arise.

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

As of December 31, 2015, we had $70.0 million principal amount outstanding under the term loan facility at an interest rate of 2.875% and no amounts outstanding under the revolving credit facility. We currently have available borrowing capacity of $500 million under the revolving credit facility.

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, 2015, we had $41.1 million in letters of credit outstanding under the Reimbursement Agreement.

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

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

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

2015 Term Loan Agreement — On March 18, 2015, we entered into a Term Loan Agreement (the "2015 Term Loan Agreement") with Wells Fargo Bank, N.A., as administrative agent and lender, each of the other lenders party thereto, Wells Fargo Securities, LLC, as Lead Arranger and Sole Book Runner, and Bank of America, N.A. and The Bank Of Tokyo-Mitsubishi UFJ, LTD., as Co-Syndication Agents.

The 2015 Term Loan Agreement is a senior unsecured single-advance term loan facility pursuant to which we made a term loan borrowing of $200 million on March 18, 2015 (the "Term Loan Borrowing"). The Term Loan Borrowing is payable in quarterly principal installments, together with accrued interest, on each June 30, September 30, December 31 and March 31, commencing on June 30, 2015. Each of the first four principal installments is in an amount equal to

2.5% of the Term Loan Borrowing and each successive quarterly installment, until and including June 30, 2017, is in an amount equal to 5.0% of the Term Loan Borrowing, with the outstanding principal balance of the Term Loan Borrowing due on the maturity date under the 2015 Term Loan Agreement. The maturity date under the 2015 Term Loan Agreement is September 27, 2017. Loans under the 2015 Term Loan Agreement bear interest, at our election, at the per annum rate of LIBOR rate plus 3.25% or base rate plus 2.25%.

Each of our domestic subsidiaries will unconditionally guarantee all existing and future indebtedness and liabilities of the other guarantors and us arising under the 2015 Term Loan Agreement and other Loan Documents (as defined in the 2015 Term Loan Agreement), other than (a) Ambar Lone Star Fluid Services LLC, (b) domestic subsidiaries that directly or indirectly have no material assets other than equity interests in, or capitalization indebtedness owed by, foreign subsidiaries, and (c) any subsidiary having total assets of less than $1 million.

The 2015 Term Loan Agreement requires quarterly compliance with two financial covenants. We must not permit our debt to capitalization ratio to exceed 45%. The 2015 Term Loan 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 most recently ended fiscal quarter. We also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 3.00 to 1.00. The 2015 Term Loan Agreement generally defines the interest coverage ratio as the ratio of EBITDA of the four prior fiscal quarters to interest charges for the same period. We were in compliance with these financial covenants as of December 31, 2015.

The 2015 Term Loan Agreement further provides that neither we nor our subsidiaries are permitted to make restricted payments unless, after giving effect to such restricted payment, our pro forma ratio of debt to EBITDA for the four prior fiscal quarters, determined as of the preceding ending quarterly period, does not exceed 2.50 to 1.00. Restricted payments are generally defined as (a) dividends and distributions made on account of our equity interests or our subsidiaries and (b) payments made to redeem, repurchase or otherwise retire our equity interests or our subsidiaries. Payments made solely in the form of common equity interests, made to us and our subsidiaries, or made in connection with our long-term incentive plans are not restricted payments under the 2015 Term Loan Agreement. We do not expect that the restrictions and covenants will impair, in any material respect, our ability to operate or react to opportunities that might arise.

The 2015 Term Loan Agreement also contains customary representations, warranties, affirmative and negative covenants, and events of default. Events of default under the 2015 Term Loan Agreement include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, as well as a cross default event, Loan Document enforceability event, change of control event and bankruptcy and other insolvency events. If an event of default occurs and is continuing, then a majority of the lenders have the right, among others, to accelerate and require us to repay all the outstanding amounts owed under any Loan Document (provided that in limited circumstances with respect to insolvency and bankruptcy, such acceleration is automatic).

As of December 31, 2015, we had $185 million principal amount outstanding under the 2015 Term Loan Agreement at an interest rate of 3.875%.

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

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

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

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

The respective note purchase agreements require compliance with two financial covenants. We must not permit our debt to capitalization ratio to exceed 50% at any time. The note purchase agreements generally define the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. We also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 2.50 to 1.00. The note purchase agreements generally define the interest coverage ratio as the ratio of EBITDA for the four prior fiscal quarters to interest charges for the same period. We were in compliance with these covenants at December 31, 2015. We do not expect that the restrictions and covenants will impair, in any material respect, our ability to operate or react to opportunities that might arise.

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

Commitments and Contingencies — As of December 31, 2015, we maintained letters of credit in the aggregate amount of $41.1 million for the benefit of various insurance companies as collateral for retrospective premiums and retained losses which could become payable under the terms of the underlying insurance contracts. These letters of credit expire annually at various times during the year and are typically renewed. As of December 31, 2015, no amounts had been drawn under the letters of credit.

As of December 31, 2015, we had commitments to purchase approximately $73.5 million of major equipment for our drilling and pressure pumping businesses.

Our pressure pumping business has entered into agreements to purchase minimum quantities of proppants and chemicals from certain vendors. These agreements expire in 2016, 2017 and 2018. As of December 31, 2015, the remaining obligation under these agreements was approximately $26.6 million, of which materials with a total purchase price of approximately $9.5 million were required to be purchased during 2016. In the event that the required minimum quantities are not purchased during any contract year, we could be required to make a liquidated damages payment to the respective vendor for any shortfall.

In November 2011, our pressure pumping business entered into an agreement with a proppant vendor to advance up to $12.0 million to such vendor to finance its construction of certain processing facilities. This advance is secured by the underlying processing facilities and bears interest at an annual rate of 5.0%. Repayment of the advance is to be made through discounts applied to purchases from the vendor and repayment of all amounts advanced must be made no later than October 1, 2017. As of December 31, 2015, advances of approximately $11.8 million had been made under this agreement and repayments of approximately $10.6 million had been received resulting in a balance outstanding of approximately $1.2 million.

A $12.3 million charge related to the previously disclosed settlement of a lawsuit filed by the U.S. Equal Employment Opportunity Commission against our U.S. contract drilling subsidiary was recorded in the first quarter of 2015.

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, 2015 (dollars in thousands):

	Payments due by period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Term loan (1)	$70,000	$28,750	$41,250	$—	$—
Interest on term loan (2)	2,734	2,046	688	—	—

2015 Term Loan (3)	185,000	35,000	150,000	—	—
Interest on 2015 Term Loan (4)	10,913	6,843	4,070	—	—
Series A Notes (5)	300,000	—	—	300,000	—
Interest on Series A Notes (6)	71,030	14,910	29,820	26,300	—
Series B Notes (7)	300,000	—	—	—	300,000
Interest on Series B Notes (8)	82,696	12,810	25,620	25,620	18,646
Leases (9)	30,162	10,522	9,022	5,963	4,655
Equipment purchases (10)	73,464	73,464	—	—	—
Inventory purchases (11)	26,550	9,525	17,025	—	—
	$1,152,549	$193,870	$277,495	$357,883	$323,301

(1) Represents repayments of borrowings under the term loan portion of the Credit Agreement. The term loan matures on September 27, 2017.
(2) Interest to be paid on term loan using 2.875% rate in effect through March 31, 2016 and using 3.375% thereafter.
(3) Represents repayments of borrowings under the 2015 Term Loan Agreement. The 2015 Term Loan Agreement matures on September 27, 2017.
(4) Interest to be paid on 2015 Term Loan using 3.875% rate in effect as of December 31, 2015.
(5) Principal repayment of the Series A Notes is required at maturity on October 5, 2020.
(6) Interest to be paid on the Series A Notes using 4.97% coupon rate.
(7) Principal repayment of the Series B Notes is required at maturity on June 14, 2022.
(8) Interest to be paid on the Series B Notes using 4.27% coupon rate.
(9) See Note 11 of Notes to Consolidated Financial Statements.
(10) Represents commitments to purchase major equipment to be delivered in 2016 based on expected delivery dates.
(11) 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, 2015.

Results of Operations

Comparison of the years ended December 31, 2015 and 2014

The following tables summarize operations by business segment for the years ended December 31, 2015 and 2014:

	Year Ended December 31,		
Contract Drilling	2015	2014	% Change
	(Dollars in thousands)		
Revenues	$1,153,892	$1,838,830	(37.2)%
Direct operating costs	608,848	1,066,659	(42.9)%
Margin (1)	545,044	772,171	(29.4)%
Selling, general and administrative	17,840	6,297	183.3 %
Depreciation, amortization and impairment	618,434	524,023	18.0 %
Operating income (loss)	$(91,230)	$241,851	NA
Operating days	45,142	77,000	(41.4)%
Average revenue per operating day	$25.56	$23.88	7.0 %
Average direct operating costs per operating day	$13.49	$13.85	(2.6)%
Average margin per operating day (1)	$12.07	$10.03	20.3 %
Average rigs operating	123.7	211.0	(41.4)%
Capital expenditures	$527,054	$771,593	(31.7)%

(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.

The demand for our contract drilling services is impacted by the market price of oil and natural gas. The decline in prices for oil and natural gas, together with the reactivation and construction of new land drilling rigs in the United States in recent years have resulted in an excess capacity of land drilling rigs compared to demand. Also in recent years, customer demand has shifted away from mechanically powered drilling rigs to electric powered drilling rigs, reducing the utilization rates of our mechanically powered drilling rigs. The average market price of oil and natural gas for each of the fiscal quarters and full year in 2015 and 2014 follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year
2014:					
Average oil price per Bbl (1)	$98.75	$103.35	$97.78	$73.16	$93.26
Average natural gas price per Mcf (2)	$5.21	$4.61	$3.96	$3.80	$4.39
2015:					
Average oil price per Bbl (1)	$48.54	$57.85	$46.42	$41.96	$48.69
Average natural gas price per Mcf (2)	$2.90	$2.75	$2.76	$2.12	$2.63

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

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

The decreases in revenues and direct operating costs primarily result from the decrease in the number of rigs operating. Average revenue per operating day and average margin per operating day were higher in 2015 primarily due to higher average dayrates and early termination revenues of approximately $69.4 million. Selling, general and administrative expense for 2015 includes a $12.3 million charge related to a previously disclosed legal settlement. Depreciation, amortization and impairment expense for 2015 includes a charge of $131 million related to the write-down of drilling equipment primarily related to mechanical rigs and spare mechanical rig components. Depreciation, amortization and impairment expense for 2014 includes a charge of $77.9 million related to the retirement of mechanical drilling rigs and the write-off of excess spare mechanical rig components. The increase in depreciation expense also reflects significant capital expenditures incurred in recent years to build new drilling rigs, to modify and upgrade existing drilling rigs and to acquire additional related equipment such as top drives, drill pipe, drill collars, engines, fluid circulating systems, rig hoisting systems and safety enhancement equipment.

	Year Ended December 31,		
Pressure Pumping	2015	2014	% Change
	(Dollars in thousands)		
Revenues	$712,454	$1,293,265	(44.9)%
Direct operating costs	612,021	1,036,310	(40.9)%
Margin (1)	100,433	256,955	(60.9)%
Selling, general and administrative	16,318	20,279	(19.5)%
Depreciation, amortization and impairment	214,552	147,595	45.4 %
Impairment of goodwill	124,561	—	NA
Operating income (loss)	$(254,998)	$89,081	NA
Fracturing jobs	610	1,224	(50.2)%
Other jobs	2,080	4,253	(51.1)%
Total jobs	2,690	5,477	(50.9)%
Average revenue per fracturing job	$1,117.95	$991.89	12.7 %
Average revenue per other job	$14.66	$18.62	(21.3)%
Average revenue per total job	$264.85	$236.13	12.2 %
Average direct operating costs per total job	$227.52	$189.21	20.2 %
Average margin per total job (1)	$37.34	$46.92	(20.4)%
Margin as a percentage of revenues (1)	14.1 %	19.9 %	(29.1)%
Capital expenditures and acquisitions	$197,577	$241,359	(18.1)%

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

Revenues and direct operating costs decreased primarily due to a decrease in the number of jobs, although the average size of the fracturing jobs increased. Average revenue per fracturing job and average direct operating costs per total job increased as a result of the increased size of the jobs in 2015 as compared to 2014. The total number of jobs decreased as a result of the downturn in the oil and natural gas industry. Depreciation, amortization and impairment expense for 2015 includes a charge of $22.0 million related to the write-down of pressure pumping equipment and closed facilities. There were no similar charges in 2014. Depreciation expense also increased due to capital expenditures and acquisitions. All of the goodwill associated with our pressure pumping business was impaired during 2015.

Oil and Natural Gas Production and Exploration	2015	2014	% Change
	Year Ended December 31, (Dollars in thousands)		
Revenues - Oil	$22,318	$44,436	(49.8)%
Revenues – Natural gas and liquids	2,613	5,760	(54.6)%
Revenues - Total	24,931	50,196	(50.3)%
Direct operating costs	11,500	13,102	(12.2)%
Margin (1)	13,431	37,094	(63.8)%
Depletion and impairment	26,301	42,576	(38.2)%
Operating loss	$(12,870)	$(5,482)	134.8 %
Capital expenditures	$16,625	$36,683	(54.7)%

33

(1) Margin is defined as revenues less direct operating costs and excludes depletion and impairment.

Oil and natural gas and liquids revenues decreased as a result of lower commodity prices. Direct operating costs include a reduction in taxes due to lower revenues. Depletion and impairment expense in 2015 includes approximately $10.7 million of oil and natural gas property impairments compared to approximately $20.9 million of oil and natural gas property impairments in 2014.

	Year Ended December 31,		
Corporate and Other	2015	2014	% Change
	(Dollars in thousands)		
Selling, general and administrative	$53,015	$53,569	(1.0)%
Depreciation	$5,472	$4,536	20.6 %
Net gain on asset disposals	$(10,613)	$(15,781)	(32.7)%
Interest income	$964	$979	(1.5)%
Interest expense	$36,475	$29,825	22.3 %
Other income	$34	$3	1,033.3%
Capital expenditures	$2,520	$2,706	(6.9)%

Gains and losses on the disposal of assets are treated as part of our corporate activities because such transactions relate to corporate strategy decisions of our executive management group. Interest expense increased primarily due to borrowings under the 2015 Term Loan Agreement.

Comparison of the years ended December 31, 2014 and 2013

The following tables summarize operations by business segment for the years ended December 31, 2014 and 2013:

	Year Ended December 31,		
Contract Drilling	2014	2013	% Change
	(Dollars in thousands)		
Revenues	$1,838,830	$1,679,611	9.5 %
Direct operating costs	1,066,659	968,754	10.1 %
Margin (1)	772,171	710,857	8.6 %
Selling, general and administrative	6,297	5,867	7.3 %
Depreciation, amortization and impairment	524,023	438,728	19.4 %
Operating income	$241,851	$266,262	(9.2)%
Operating days	77,000	69,918	10.1 %
Average revenue per operating day	$23.88	$24.02	(0.6)%
Average direct operating costs per operating day	$13.85	$13.86	(0.1)%
Average margin per operating day (1)	$10.03	$10.17	(1.4)%
Average rigs operating	$211.0	191.6	10.1 %
Capital expenditures	$771,593	$504,508	52.9 %

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

The demand for our contract drilling services is impacted by the market price of oil and natural gas. The reactivation and construction of new land drilling rigs in the United States in recent years contributed to an excess capacity of land drilling rigs compared to demand. Customer demand shifted away from mechanically powered drilling rigs to electric powered drilling rigs, reducing the utilization rates of our mechanically powered drilling rigs. The average market price of oil and natural gas for each of the fiscal quarters and full year in 2014 and 2013 follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year
2013:					
Average oil price per Bbl (1)	$94.37	$94.10	$105.84	$97.34	$97.91
Average natural gas price per Mcf (2)	$3.49	$4.01	$3.55	$3.85	$3.73
2014:					
Average oil price per Bbl (1)	$98.75	$103.35	$97.78	$73.16	$93.26
Average natural gas price per Mcf (2)	$5.21	$4.61	$3.96	$3.80	$4.39

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

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

Revenues and direct operating costs increased in 2014 compared to 2013 as a result of an increase in the number of rigs operating. Revenues in 2013 included approximately $65.2 million of early termination revenues. Average revenue per operating day and average margin per operating day were higher in 2013 due to the early termination revenue. Capital expenditures were incurred in 2014 and 2013 to build new drilling rigs, to modify and upgrade existing drilling rigs and to acquire additional equipment including top drives, drill pipe, drill collars, engines, fluid circulating systems, rig hoisting systems and safety enhancement equipment. In 2014, we identified 55 mechanical rigs that we determined would no longer be marketed. We recorded additional depreciation, amortization and impairment expense of $77.9 million related to the retirement of these mechanical rigs and the write-off of excess spare components for the now reduced size of our mechanical fleet. In 2013, we identified 48 rigs that would no longer be marketed. Also, we had 55 additional mechanical rigs that were not operating. Although these 55 rigs remained marketable at the time, we had lower expectations with respect to utilization of these rigs due to the industry shift to electric powered drilling rigs. We recorded a charge of $37.8 million related to the retirement of the 48 rigs and the 55 mechanical rigs that remained marketable but were not operating. Significant capital expenditures incurred in recent years to add new rig capacity also contributed to the increase in depreciation expense.

Pressure Pumping	Year Ended December 31, 2014	2013	% Change
	(Dollars in thousands)		
Revenues	$1,293,265	$979,166	32.1 %
Direct operating costs	1,036,310	744,243	39.2 %
Margin (1)	256,955	234,923	9.4 %
Selling, general and administrative	20,279	17,695	14.6 %
Depreciation, amortization and impairment	147,595	129,984	13.5 %
Operating income	$89,081	$87,244	2.1 %
Fracturing jobs	1,224	1,261	(2.9)%
Other jobs	4,253	4,800	(11.4)%

Total jobs	5,477	6,061	(9.6)%
Average revenue per fracturing job	$991.89	$705.57	40.6 %
Average revenue per other job	$18.62	$18.63	(0.1)%
Average revenue per total job	$236.13	$161.55	46.2 %
Average direct operating costs per total job	$189.21	$122.79	54.1 %
Average margin per total job (1)	$46.92	$38.76	21.1 %
Margin as a percentage of revenues (1)	19.9 %	24.0 %	(17.1)%
Capital expenditures	$241,359	$122,782	96.6 %

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

Revenues and direct operating costs increased primarily due to an increase in the size of our jobs and the size of our pressure pumping fleet. Our customers continued the development of unconventional reservoirs resulting in an increase in larger multi-stage fracturing jobs associated therewith. In connection with the horizontal shale and other unconventional resource plays, we added equipment to perform service intensive fracturing jobs, including the June 2014 acquisition of an East Texas-based pressure pumping operation and the October 2014 acquisition of a Texas-based pressure pumping operation. As a result, we continued to experience an increase in the number of these larger multi-stage fracturing jobs as a proportion of the total fracturing jobs we performed. Additionally, the average size of the multi-stage fracturing jobs increased. Average revenue per fracturing job and average direct operating costs per total job increased as a result of this increase in the proportion of larger multi-stage fracturing jobs and the increased size of the jobs in 2014 as compared to 2013. Depreciation expense increased due to capital expenditures.

	Year Ended December 31,		
Oil and Natural Gas Production and Exploration	2014	2013	% Change
	(Dollars in thousands)		
Revenues - Oil	$44,436	$51,583	(13.9)%
Revenues – Natural gas and liquids	5,760	5,674	1.5 %
Revenues - Total	50,196	57,257	(12.3)%
Direct operating costs	13,102	12,909	1.5 %
Margin (1)	37,094	44,348	(16.4)%
Depletion and impairment	42,576	24,400	74.5 %
Operating income (loss)	$(5,482)	$19,948	NA
Capital expenditures	$36,683	$31,245	17.4 %

(1) Margin is defined as revenues less direct operating costs and excludes depletion and impairment.

Oil revenues decreased as a result of lower average oil prices and lower production. Natural gas and liquids revenue increased due to higher average prices, partially offset by lower production. Direct operating costs and depletion expense increased primarily due to the addition of new wells. Depletion and impairment expense in 2014 includes approximately $20.9 million of oil and natural gas property impairments, compared to approximately $4.0 million of oil and natural gas property impairments in 2013. The impairment in 2014 is primarily the result of lower oil prices.

	Year Ended December 31,		
Corporate and Other	2014	2013	% Change
	(Dollars in thousands)		
Selling, general and administrative	$53,569	$50,290	6.5 %
Depreciation	$4,536	$4,357	4.1 %
Net gain on asset disposals	$(15,781)	$(3,384)	366.3 %
Interest income	$979	$918	6.6 %
Interest expense	$29,825	$28,359	5.2 %
Other income	$3	$1,691	(99.8)%
Capital expenditures	$2,706	$3,926	(31.1)%

Selling, general and administrative expense for 2014 increased primarily due to higher personnel costs. Gains and losses on the disposal of assets are treated as part of our corporate activities because such transactions relate to corporate strategy decisions of our executive management group. The net gain on the disposal of assets in 2014 resulted primarily from miscellaneous sales of drilling equipment and sales of certain oil and natural gas properties.

36

Adjusted EBITDA

Adjusted earnings before interest, taxes, depreciation and amortization ("Adjusted EBITDA") is not defined by 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. We present Adjusted EBITDA (a non-U.S. GAAP measure) because we believe it provides to both management and investors additional information with respect to both the performance of our fundamental business activities and our ability to meet our capital expenditures and working capital requirements. Adjusted EBITDA should not be construed as an alternative to the U.S. GAAP measures of net income (loss) or operating cash flow.

	Year Ended December 31,		
	2015	2014	2013
	(Dollars in thousands)		
Net income (loss)	$(294,486)	$162,664	$188,009
Income tax expense (benefit)	(147,963)	91,619	108,432
Net interest expense	35,511	28,846	27,441
Depreciation, depletion, amortization and impairment	864,759	718,730	597,469
Impairment of goodwill	124,561	—	—
Adjusted EBITDA	$582,382	$1,001,859	$921,351

Income Taxes

	Year Ended December 31,		
	2015	2014	2013
	(Dollars in thousands)		
Income (loss) before income taxes	$(442,449)	$254,283	$296,441
Income tax expense (benefit)	$(147,963)	$91,619	$108,432
Effective tax rate	33.4 %	36.0 %	36.6 %

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

	2015	2014	2013
Statutory tax rate	35.0%	35.0%	35.0%
State income taxes	2.1	2.5	3.7
Permanent differences	(1.3)	(1.4)	(1.5)
Other differences, net	(2.4)	(0.1)	(0.6)
Effective tax rate	33.4%	36.0%	36.6%

The Domestic Production Activities Deduction (IRC section 199 deduction) was enacted as part of the American Jobs Creation Act of 2004 (as revised by the Emergency Economic Stabilization Act of 2008) and allows a deduction of

9% in 2010 and thereafter on the lesser of qualified production activities income or taxable income. The permanent differences for 2013 include a deduction of $10.0 million as we fully utilized our remaining net operating loss carryforwards. The permanent differences for 2014 include a deduction of $8.8 million. The permanent differences for 2015 do not include any deduction as it is limited to taxable income, and we did not have taxable income in 2015 as a result of our election to utilize bonus depreciation.

The 2015 other differences include a 1.0% reduction related to the reconciliation of the deferred tax liability associated with the conversion of our Canadian operations to a controlled foreign corporation. The impact to the deferred tax liability from the conversion is being amortized over the weighted average remaining useful life of the Canadian assets. The 2015 other differences also include a 0.7% reduction for the lost benefit of the 2014 IRC section 199 deduction of $8.8 million as a result of our adoption of the final tangible property regulations with the filing of the 2014 tax return.

We record deferred federal income taxes based primarily on the temporary differences between the book and tax bases of our assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the year in which those temporary differences are expected to be settled. As a result of fully recognizing the benefit of our deferred income taxes, we incur deferred income tax expense as these benefits are utilized. We recognized a deferred tax benefit of approximately $100 million in 2015 and deferred tax expense of approximately $44 million in 2014 and $51 million in 2013.

On January 1, 2010, we converted our Canadian operations from a Canadian branch to a controlled foreign corporation for federal income tax purposes. This transaction triggered a $1 million increase in deferred tax liabilities, which is being amortized as an increase to deferred income tax expense over the weighted average remaining useful life of the Canadian assets. This will be fully amortized by December 31, 2016.

As a result of the above conversion, our Canadian assets are no longer directly subject to United States taxation, provided that the related unremitted earnings are permanently reinvested in Canada. Effective January 1, 2010, we have elected to permanently reinvest these unremitted earnings in Canada, and intend to do so for the foreseeable future. As a result, no deferred United States federal or state income taxes have been provided on such unremitted foreign earnings, which totaled approximately $28.4 million as of December 31, 2015. The unrecognized deferred tax liability associated with these earnings was approximately $3.8 million, net of available foreign tax credits. This liability would be recognized if we received a dividend of the unremitted earnings.

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 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 have significantly declined since the second half of 2014. The closing price of oil, which was as high as $105.68 per barrel during the third quarter of 2014, reached a low price for 2015 of $34.55 in December 2015 and reached a twelve-year low of $26.68 in January 2016. As a result of the prolonged decline in oil prices, our industry continues to experience a severe decline in both contract drilling and pressure pumping activity levels. We do not expect this to change until commodity prices improve.

We expect oil and natural gas prices to continue to be volatile and to affect our financial condition, operations and ability to access sources of capital. Higher oil and natural gas prices do not necessarily result in increased activity because demand for our services is generally driven by our customers’ expectations of future oil and natural gas prices. A continued decline in demand for oil and natural gas or prolonged low oil or natural gas prices would likely result in further reduced capital expenditures by our customers and decreased demand for our drilling rigs and pressure pumping services, which could have a material adverse effect on our operating results, financial condition and cash flows.

Impact of Inflation

Inflation has not had a significant impact on our operations during the three years ended December 31, 2015. We believe that inflation will not have a significant near-term impact on our financial position.

Recently Issued 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 requirements in this update are effective during interim and annual periods beginning after December 15, 2016. We are currently evaluating the impact this guidance will have on our consolidated financial statements.

In June 2014, the FASB issued an accounting standards update to provide guidance on the accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the requisite service period. The guidance requires that a performance target that affects vesting and that could be achieved after the requisite service period is treated as a performance condition. The requirements in this update are effective during interim and annual periods beginning after December 15, 2015. The adoption of this update is not expected to have a material impact on our consolidated financial statements.

In April 2015, the FASB issued an accounting standards update to provide guidance for the presentation of debt issuance costs. Under this guidance, debt issuance costs shall be presented in the balance sheet as a direct deduction from the carrying amount of the related debt and shall not be classified as a deferred charge. Amortization of debt issuance costs shall continue to be reported as interest expense. The requirements in this update are effective during interim and annual periods beginning after December 15, 2015. The adoption of this update is not expected to have a material impact on our consolidated financial statements.

In November 2015, the FASB issued an accounting standards update to provide guidance for the presentation of deferred tax liabilities and assets. Under this guidance, for a particular tax-paying component of an entity and within a particular tax jurisdiction, all deferred tax liabilities and assets, as well as any related valuation allowance, shall be offset and presented as a single noncurrent amount. The requirements in this update are effective during interim and annual periods beginning after December 15, 2016. The adoption of this update is not expected to have a material impact on our consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We currently have exposure to interest rate market risk associated with any borrowings that we have under the Credit Agreement, the 2015 Term Loan Agreement and the Reimbursement Agreement.

Under the Credit Agreement, interest is paid on the outstanding principal amount of borrowings at a floating rate based on, at our election, LIBOR or a base rate. The margin on LIBOR loans ranges from 2.25% to 3.25% and the margin on base rate loans ranges from 1.25% to 2.25%, based on our debt to capitalization ratio. At December 31, 2015, the margin on LIBOR loans was 2.25% and the margin on base rate loans was 1.25%. Based on our debt to capitalization ratio at September 30, 2015, the applicable margin on LIBOR loans is 2.25% and the applicable margin on base rate loans is 1.25% as of January 1, 2016. Based on our debt to capitalization ratio at December 31, 2015, the applicable margin on LIBOR loans will be 2.75% and the applicable margin on base rate loans will be 1.75% as of April 1, 2016. As of December 31, 2015, we had no amounts outstanding under our revolving credit facility and $70.0 million outstanding under our term loan facility at an interest rate of 2.875%. The interest rate on the borrowings outstanding under the Credit Agreement is variable and adjusts at each interest payment date based on our election of LIBOR or the base rate. A one percent increase in the interest rate on the borrowings outstanding under our term credit facility as of December 31, 2015 would increase our annual cash interest expense by approximately $632,000.

Loans under the 2015 Term Loan Agreement bear interest, at our election, at the per annum rate of LIBOR plus 3.25% or base rate plus 2.25%. As of December 31, 2015, we had $185 million principal amount outstanding under the 2015 Term Loan Agreement at an interest rate of 3.875%. A one percent increase in the interest rate on the borrowings outstanding under 2015 Term Loan Agreement as of December 31, 2015 would increase our annual cash interest expense by approximately $1.8 million.

Under the Reimbursement Agreement, we will reimburse the issuing bank on demand for any amounts that it has disbursed under any letters of credit. We are obligated to pay to the issuing bank interest on all amounts not paid by us on the date of demand or when otherwise due at the LIBOR rate plus 2.25% per annum. As of December 31, 2015, no amounts had been disbursed under any letters of credit.

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

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

Item 8. Financial Statements and Supplementary Data.

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

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

None.

Item 9A. Controls and Procedures.

Disclosure Controls and Procedures:

Under the supervision and with the participation of our management, including our Chief Executive Officer (“CEO”) and Chief Financial Officer (“CFO”), we conducted an evaluation of the effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Exchange Act, as of the end of the period covered by this Report. Based on this evaluation, our CEO and CFO concluded that, as of December 31, 2015, 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, 2015, 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, 2015.

The effectiveness of our internal control over financial reporting as of December 31, 2015 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.

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 for the quarterly period ended June 30, 2004 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 for the quarterly period ended June 30, 2004 and incorporated herein by reference).
3.3	Certificate of Elimination with respect to Series A Participating Preferred Stock (filed October 27, 2011 as Exhibit 3.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
3.4	Second Amended and Restated Bylaws (filed August 6, 2007 as Exhibit 3.3 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 and incorporated herein by reference).
10.1	Registration Rights Agreement

	with Bear, Stearns and Co. Inc., dated March 25, 1994, as assigned to REMY Capital Partners III, L.P. (filed March 19, 2002 as Exhibit 4.3 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2001 and incorporated herein by reference).
10.2	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).*
10.3	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).*
10.4	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).*
10.5	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).*
10.6	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).*
10.7	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).*
10.8	Form of Share-Settled Performance Unit Award Agreement under the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed August 2, 2010 as Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2010 and incorporated herein by reference).*
10.9	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).*
10.10	Form of Executive Officer Share-Settled Performance Share Award Agreement

(filed April 21, 2014 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.11	Form of Executive Officer Restricted Stock Award Agreement (filed April 21, 2014 as Exhibit 10.3 to the Company's Current Report on Form 8-K, and incorporated herein by reference).*
10.12	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).*
10.13	Form of Non-Employee Director Restricted Stock Award Agreement (filed April 21, 2014 as Exhibit 10.5 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.14 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 Letter Agreement regarding termination, effective as of January 29, 2004, entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Kenneth N. Berns and John E. Vollmer III (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).*

10.16 Employment Agreement, effective as of January 1, 2012, by and between

	Patterson-UTI Drilling Company LLC and James M. Holcomb (filed February 10, 2012 as Exhibit 10.17 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011 and incorporated herein by reference). *
10.17	Form of Indemnification Agreement entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Kenneth N. Berns, Curtis W. Huff, Terry H. Hunt, Charles O. Buckner, John E. Vollmer III, Seth D. Wexler, William Andrew Hendricks, Jr., Michael W. Conlon and Tiffany J. Thom (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).*
10.18	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).*
10.19	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).*
10.20	Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and John E. Vollmer III (filed on February 4, 2004 as Exhibit 10.7 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*
10.21	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 for the quarterly period ended September 30, 2007 and incorporated herein by reference).*
10.22	First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and John E. Vollmer, III, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*
10.23	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 for the quarterly period ended September 30, 2007 and incorporated herein by reference).*
10.24	Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of November 2, 2009, by and between Patterson-UTI Energy, Inc. and Seth D. Wexler (filed November 2, 2009 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2009 and incorporated herein by reference).*
10.25	Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of April 2, 2012, by and between Patterson-UTI Energy, Inc. and William

	Andrew Hendricks, Jr. (filed July 30, 2012 as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012 and incorporated herein by reference).*
10.26	Credit Agreement dated September 27, 2012, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender and each of the other letter of credit issuer and lender parties thereto (filed September 28, 2012 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.27	Amendment No. 1 to Credit Agreement dated as of

	January 9, 2015, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender and each of the other letter of credit issuer and lender parties thereto (filed January 12, 2015 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.28	Note Purchase Agreement dated October 5, 2010 by and among Patterson-UTI Energy, Inc. and the purchasers named therein (filed October 6, 2010 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.29	Amendment No. 1 to Purchase Agreement, dated as of October 22, 2015, by and among Patterson-UTI Energy, Inc., certain subsidiaries of Patterson-UTI Energy, Inc. party thereto, and the purchasers named therein (relates to Note Purchase Agreement dated October 5, 2010) (filed October 28, 2015 as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2015 and incorporated herein by reference).
10.30	Note Purchase Agreement dated June 14, 2012 by and among Patterson-UTI Energy, Inc. and the purchasers named therein (filed June 18, 2012 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.31	Amendment No. 1 to Purchase Agreement, dated as of October 22, 2015, by and among Patterson-UTI Energy, Inc., certain subsidiaries of

	Patterson-UTI Energy, Inc. party thereto, and the purchasers named therein (relates to Note Purchase Agreement dated June 14, 2012) (filed October 28, 2015 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2015 and incorporated herein by reference).
10.32	Reimbursement Agreement, dated as 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).
10.33	Continuing Guaranty, dated as of March 16, 2015, by Patterson Petroleum LLC, Patterson-UTI Drilling Company LLC, Patterson-UTI Management Services, LLC, Universal Well Services, Inc. and Universal Pressure

	Pumping, Inc. (filed March 16, 2015 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.34	Term Loan Agreement, dated as March 18, 2015, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent and lender, each of the other lenders party thereto, Wells Fargo Securities, LLC, as Lead Arranger and Sole Book Runner, and Bank of America, N.A. and The Bank of Tokyo-Mitsubishi UFJ, LTD., as Co-Syndication Agents (filed March 18, 2015 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).
10.35	Continuing Guaranty, dated as of March 18, 2015, by Patterson Petroleum LLC, Patterson-UTI Drilling Company LLC, Patterson-UTI Management

	Services, LLC, Universal Well Services, Inc. and Universal Pressure Pumping, Inc. (filed March 18, 2015 as Exhibit 10.2 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.+

99.1	Stipulation and Proposed Order of Dismissal, dated December 17, 2015.+
101	The following materials from Patterson-UTI Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2015, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Changes in Stockholders' Equity, (v) the Consolidated Statements of Cash Flows, and (vi) Notes to Consolidated Financial Statements.+

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

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Patterson-UTI Energy, Inc. and its subsidiaries (the "Company") at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). The Company's management is responsible for these financial statements and financial statement schedule, 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 these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. 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.

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

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

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 10, 2016

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2015	2014
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$113,346	$43,012
Accounts receivable, net of allowance for doubtful accounts of $3,545 and $3,546 at December 31, 2015 and 2014, respectively	219,672	663,404
Federal and state income taxes receivable	33,454	81,726
Inventory	14,716	32,251
Deferred tax assets, net	65,121	37,075
Other	40,227	51,624
Total current assets	486,536	909,092
Property and equipment, net	3,920,708	4,131,071
Goodwill and intangible assets	92,609	220,813
Deposits on equipment purchases	22,367	112,379
Other	11,097	20,656
Total assets	$4,533,317	$5,394,011
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current liabilities:		
Accounts payable	$82,771	$382,438
Accrued expenses	161,611	173,466
Current portion of long-term debt	63,750	12,500
Total current liabilities	308,132	568,404
Borrowings under revolving credit facility	—	303,000
Other long-term debt	791,250	670,000
Deferred tax liabilities, net	863,833	935,660
Other	8,971	11,137
Total liabilities	1,972,186	2,488,201
Commitments and contingencies (see Note 8)		
Stockholders’ equity:		
Preferred stock, par value $.01; authorized 1,000,000 shares, no shares issued	—	—
Common stock, par value $.01; authorized 300,000,000 shares with 190,374,801 and 189,262,876 issued and 147,167,561 and 146,444,291 outstanding at December 31, 2015 and 2014, respectively	1,904	1,893
Additional paid-in capital	1,011,811	984,674
Retained earnings	2,458,554	2,811,815
Accumulated other comprehensive income (loss)	(4,093)	6,463
Treasury stock, at cost, 43,207,240 shares and 42,818,585 shares at	(907,045)	(899,035)

December 31, 2015 and 2014, respectively		
Total stockholders’ equity	2,561,131	2,905,810
Total liabilities and stockholders’ equity	$4,533,317	$5,394,011

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,		
	2015	2014	2013
	(In thousands, except per share data)		
Operating revenues:			
Contract drilling	$1,153,892	$1,838,830	$1,679,611
Pressure pumping	712,454	1,293,265	979,166
Oil and natural gas	24,931	50,196	57,257
Total operating revenues	1,891,277	3,182,291	2,716,034
Operating costs and expenses:			
Contract drilling	608,848	1,066,659	968,754
Pressure pumping	612,021	1,036,310	744,243
Oil and natural gas	11,500	13,102	12,909
Depreciation, depletion, amortization and impairment	864,759	718,730	597,469
Impairment of goodwill	124,561	—	—
Selling, general and administrative	87,173	80,145	73,852
Net gain on asset disposals	(10,613)	(15,781)	(3,384)
Total operating costs and expenses	2,298,249	2,899,165	2,393,843
Operating income (loss)	(406,972)	283,126	322,191
Other income (expense):			
Interest income	964	979	918
Interest expense, net of amount capitalized	(36,475)	(29,825)	(28,359)
Other	34	3	1,691
Total other expense	(35,477)	(28,843)	(25,750)
Income (loss) before income taxes	(442,449)	254,283	296,441
Income tax expense (benefit):			
Current	(48,090)	47,946	57,863
Deferred	(99,873)	43,673	50,569
Total income tax expense (benefit)	(147,963)	91,619	108,432
Net income (loss)	$(294,486)	$162,664	$188,009
Net income (loss) per common share:			
Basic	$(2.00)	$1.12	$1.29
Diluted	$(2.00)	$1.11	$1.28
Weighted average number of common shares outstanding:			
Basic	145,416	144,066	144,356
Diluted	145,416	145,376	145,303

Cash dividends per common share	$0.40	$0.40	$0.20

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2015	2014	2013
	(In thousands)		
Net income (loss)	$(294,486)	$162,664	$188,009
Other comprehensive loss, net of taxes of $0 for 2015, $0 for 2014 and $0 for 2013:			
Foreign currency translation adjustment	(10,556)	(7,613)	(7,691)
Total comprehensive income (loss)	$(305,042)	$155,051	$180,318

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Common Stock Number of Shares	Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total
	(In thousands)						
Balance, December 31, 2012	184,060	$ 1,841	$ 863,558	$ 2,548,542	$ 21,767	$ (795,051)	$ 2,640,657
Net income	—	—	—	188,009	—	—	188,009
Foreign currency translation adjustment	—	—	—	—	(7,691)	—	(7,691)
Issuance of restricted stock	1,312	13	(13)	—	—	—	—
Vesting of restricted stock units	9	—	—	—	—	—	—
Forfeitures of restricted stock	(84)	(1)	1	—	—	—	—
Exercise of stock options	1,190	12	19,274	—	—	—	19,286
Stock-based compensation	—	—	25,891	—	—	—	25,891
Tax benefit related to stock-based compensation	—	—	4,794	—	—	—	4,794
Payment of cash dividends	—	—	—	(29,112)	—	—	(29,112)
Purchase of treasury stock	—	—	—	—	—	(85,837)	(85,837)
Balance, December 31, 2013	186,487	1,865	913,505	2,707,439	14,076	(880,888)	2,755,997
Net income	—	—	—	162,664	—	—	162,664
Foreign currency translation adjustment	—	—	—	—	(7,613)	—	(7,613)
Issuance of restricted stock	1,102	11	(11)	—	—	—	—
Vesting of restricted stock units	10	1	—	—	—	—	1
Forfeitures of restricted stock	(61)	(1)	1	—	—	—	—
Exercise of stock options	1,725	17	35,418	—	—	—	35,435
Stock-based compensation	—	—	27,032	—	—	—	27,032
Tax benefit related to stock-based compensation	—	—	8,729	—	—	—	8,729
Payment of cash dividends	—	—	—	(58,288)	—	—	(58,288)

Purchase of treasury stock	—	—	—	—	—	(18,147)	(18,147)
Balance, December 31, 2014	189,263	1,893	984,674	2,811,815	6,463	(899,035)	2,905,810
Net loss	—	—	—	(294,486)	—	—	(294,486)
Foreign currency translation adjustment	—	—	—	—	(10,556)	—	(10,556)
Issuance of restricted stock	1,180	12	(12)	—	—	—	—
Vesting of restricted stock units	14	—	—	—	—	—	—
Forfeitures of restricted stock	(82)	(1)	1	—	—	—	—
Stock-based compensation	—	—	28,510	—	—	—	28,510
Tax expense related to stock-based compensation	—	—	(1,362)	—	—	—	(1,362)
Payment of cash dividends	—	—	—	(58,775)	—	—	(58,775)
Purchase of treasury stock	—	—	—	—	—	(8,010)	(8,010)
Balance, December 31, 2015	190,375	$ 1,904	$ 1,011,811	$ 2,458,554	$ (4,093)	$ (907,045)	$ 2,561,131

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,		
	2015	2014	2013
	(In thousands)		
Cash flows from operating activities:			
Net income (loss)	$(294,486)	$162,664	$188,009
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and impairment	864,759	718,730	597,469
Impairment of goodwill	124,561	—	—
Dry holes and abandonments	1,224	550	89
Deferred income tax expense (benefit)	(99,873)	43,673	50,569
Stock-based compensation expense	28,510	27,032	25,891
Net gain on asset disposals	(10,613)	(15,781)	(3,384)
Tax expense related to stock-based compensation	(1,362)	—	—
Changes in operating assets and liabilities:			
Accounts receivable	440,884	(214,059)	12,007
Income taxes receivable/payable	49,895	(92,352)	4,447
Inventory and other assets	40,238	(5,737)	570
Accounts payable	(131,649)	86,621	11,331
Accrued expenses	(10,303)	12,838	1,973
Other liabilities	(2,348)	4,547	(100)
Net cash provided by operating activities	999,437	728,726	888,871
Cash flows from investing activities:			
Acquisitions	—	(176,301)	—
Purchases of property and equipment	(743,776)	(1,052,341)	(662,461)
Proceeds from disposal of assets	20,814	33,233	10,386
Net cash used in investing activities	(722,962)	(1,195,409)	(652,075)
Cash flows from financing activities:			
Purchases of treasury stock	(8,010)	(13,554)	(73,510)
Dividends paid	(58,775)	(58,288)	(29,112)
Tax benefit related to stock-based compensation	—	8,729	4,794
Proceeds from long-term debt	200,000	—	—
Repayment of long-term debt	(27,500)	(10,000)	(6,250)
Proceeds from borrowings under revolving credit facility	54,000	349,500	—
Repayment of borrowings under revolving credit facility	(357,000)	(46,500)	—
Debt issuance costs	(1,979)	—	—
Proceeds from exercise of stock options	—	30,842	6,959
Net cash provided by (used in) financing activities	(199,264)	260,729	(97,119)
Effect of foreign exchange rate changes on cash	(6,877)	(543)	(891)
Net increase (decrease) in cash and cash equivalents	70,334	(206,497)	138,786
Cash and cash equivalents at beginning of year	43,012	249,509	110,723
Cash and cash equivalents at end of year	$113,346	$43,012	$249,509
Supplemental disclosure of cash flow information:			
Net cash (paid) received during the year for:			

Interest, net of capitalized interest of $6,332 in 2015, $6,883 in 2014 and $7,775 in 2013	$(33,452)	$(27,813)	$(26,228)
Income taxes	97,333	(125,953)	(42,600)
Non-cash investing and financing activities:			
Net (decrease) increase in payables for purchases of property and equipment	$(167,308)	$122,148	$(26,899)
Net decrease in deposits on equipment purchases	(90,012)	(59,819)	(8,784)

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Business and Summary of Significant Accounting Policies

A description of the business and basis of presentation follows:

Description of business — Patterson-UTI Energy, Inc., through its wholly-owned subsidiaries (collectively referred to herein as “Patterson-UTI” or the “Company”), provides onshore contract drilling services to major, independent and other oil and natural gas operators in the continental United States and western Canada. The Company provides pressure pumping services to major, independent and other oil and natural gas operators primarily in Texas and the Appalachian region. The Company also invests in oil and natural gas properties on a non-operating working interest basis.

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

The U.S. dollar is the functional currency for all of the Company’s operations except for its Canadian operations, which use the Canadian dollar as its 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 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 daywork drilling and pressure pumping activities are recognized as services are performed. Expenditures reimbursed by customers are recognized as revenue and the related expenses are recognized as direct costs. All of the wells the Company drilled in 2015, 2014 and 2013 were drilled under daywork contracts.

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

Inventories — Inventories consist primarily of sand and other products to be used in conjunction with the Company’s pressure pumping activities. The inventories are stated at the lower of cost or market, determined under the average cost method.

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
Drilling rigs and other 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.

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 expected future net cash flows are discounted using an annual rate of 10% to determine fair value. The Company reviews unproved oil and natural gas properties quarterly to assess potential impairment. The Company's impairment assessment is made on a lease-by-lease basis and considers factors such as management's intent to drill, lease terms and abandonment of an area. If an unproved property is determined to be impaired, the related property costs are expensed.

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

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.

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

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

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

F-9

The following table presents information necessary to calculate net income (loss) per share for the years ended December 31, 2015, 2014 and 2013, 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):

	2015	2014	2013
BASIC EPS:			
Net income (loss)	$(294,486)	$162,664	$188,009
Adjust for (income) loss attributed to holders of non-vested restricted stock	3,022	(1,663)	(1,859)
Income (loss) attributed to common stockholders	$(291,464)	$161,001	$186,150
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	145,416	144,066	144,356
Basic net income (loss) per common share	$(2.00)	$1.12	$1.29
DILUTED EPS:			
Income (loss) attributed to common stockholders	$(291,464)	$161,001	$186,150
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	145,416	144,066	144,356
Add dilutive effect of potential common shares	—	1,310	947
Weighted average number of diluted common shares outstanding	145,416	145,376	145,303
Diluted net income (loss) per common share	$(2.00)	$1.11	$1.28
Potentially dilutive securities excluded as anti-dilutive	7,781	1,088	2,447

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 10).

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

Recently Issued Accounting Standards — In May 2014, the 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 requirements in this update are effective during interim and annual periods beginning after December 15, 2016. The Company is currently evaluating the impact this guidance will have on its consolidated financial statements.

In June 2014, the FASB issued an accounting standards update to provide guidance on the accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the requisite service period. The guidance requires that a performance target that affects vesting and that could be achieved after the requisite service period is treated as a

performance condition. The requirements in this update are effective during interim and annual periods beginning after December 15, 2015. The adoption of this update is not expected to have a material impact on the Company's consolidated financial statements.

In April 2015, the FASB issued an accounting standards update to provide guidance for the presentation of debt issuance costs. Under this guidance, debt issuance costs shall be presented in the balance sheet as a direct deduction from the carrying amount of the related debt and shall not be classified as a deferred charge. Amortization of debt issuance costs shall continue to be reported as interest expense. The requirements in this update are effective during interim and annual periods beginning after December 15, 2015. The adoption of this update is not expected to have a material impact on the Company's consolidated financial statements.

In November 2015, the FASB issued an accounting standards update to provide guidance for the presentation of deferred tax liabilities and assets. Under this guidance, for a particular tax-paying component of an entity and within a particular tax jurisdiction, all deferred tax liabilities and assets, as well as any related valuation allowance, shall be offset and presented as a single noncurrent amount. The requirements in this update are effective during interim and annual periods beginning after December 15, 2016. The adoption of this update is not expected to have a material impact on the Company's consolidated financial statements.

2. Acquisitions

During 2014, the Company completed two pressure pumping acquisitions. In June 2014, a subsidiary of the Company acquired the East Texas-based pressure pumping assets of a privately held company. This acquisition included 31,500 horsepower of hydraulic fracturing equipment. In October 2014, a subsidiary of the Company completed the acquisition of the Texas-based pressure pumping assets of a privately held company. This acquisition included 148,250 horsepower of hydraulic fracturing equipment.

In total, the Company paid $176 million in cash for these two acquisitions plus the assumption of property leases and other contractual obligations. The purchase price was allocated to the assets acquired based on fair value. A summary of the purchase price allocation follows (in thousands):

Inventory	$1,357
Equipment	117,958
Goodwill	56,986
Total purchase price	$176,301

Results of operations of the acquired businesses are included in the Company's consolidated results of operations from their respective dates of acquisition. Revenues of $80.8 million and income from operations of $13.7 million from the acquired businesses are included in the consolidated statement of operations for the year ended December 31, 2014.

The following represents pro-forma unaudited financial information for the years ended December 31, 2014 and 2013 as if the acquisitions had been completed on January 1, 2013 (in thousands, except per share amounts):

	2014	2013
	(Unaudited)	
Revenue	$3,302,492	$2,854,867
Net income	$169,831	$196,600

Basic net income per common share	$1.17	$1.35
Diluted net income per common share	$1.16	$1.34

3. Property and Equipment

Property and equipment consisted of the following at December 31, 2015 and 2014 (in thousands):

	2015	2014
Equipment	$6,963,148	$6,679,894
Oil and natural gas properties	200,923	196,234
Buildings	96,470	83,465
Land	22,370	12,038
Total property and equipment	7,282,911	6,971,631
Less accumulated depreciation, depletion and impairment	(3,362,203)	(2,840,560)
Property and equipment, net	$3,920,708	$4,131,071

Depreciation, depletion, amortization and impairment — The following table summarizes depreciation, depletion, amortization and impairment expense related to property and equipment and intangible assets for 2015, 2014 and 2013 (in thousands):

	2015	2014	2013
Depreciation and impairment expense	$845,543	$693,390	$573,106
Amortization expense	3,643	3,643	3,993
Depletion expense	15,573	21,697	20,370
Total	$864,759	$718,730	$597,469

On a periodic basis, the Company evaluates its fleet of drilling rigs for marketability based on the condition of inactive rigs, expenditures that would be necessary to bring them to working condition and the expected demand for drilling services by rig type (such as drilling conventional, vertical wells versus drilling longer, horizontal wells using higher specification rigs). The components comprising rigs that will no longer be marketed are evaluated, and those components with continuing utility to the Company's other marketed rigs are transferred to other rigs or to the Company's yards to be used as spare equipment. The remaining components of these rigs will be retired. In 2015, the Company identified 24 mechanical rigs and 9 non-APEX® electric rigs that would no longer be marketed. Also, the Company had 15 additional mechanical rigs that were not operating. Although these 15 rigs remain marketable, the Company has lower expectations with respect to utilization of these rigs due to the industry shift to higher specification drilling rigs. In 2015, the Company recorded a charge of $131 million related to the retirement of the 33 rigs, the 15 mechanical rigs that remain marketable but were not operating, and the write-down of excess spare rig components to their realizable values. In 2014, the Company identified 55 mechanical rigs that it determined would no longer be marketed, and the Company recorded a charge of $77.9 million related to the retirement of these mechanical rigs and the write-off of excess spare components for the reduced size of the Company's mechanical fleet. In 2013, the Company identified 48 rigs that would no longer be marketed. Also, the Company had 55 additional mechanical rigs that were not operating. Although these 55 rigs remained marketable at the time, the Company had lower expectations with respect to utilization of these rigs due to the industry shift to electric powered drilling rigs. In 2013, the Company recorded a charge of $37.8 million related to the retirement of the 48 rigs and the 55 mechanical rigs that remained marketable but were not operating.

The Company also periodically evaluates its pressure pumping assets, and in 2015, the Company recorded a charge of $22.0 million for the write-down of pressure pumping equipment and certain closed facilities. There were no similar charges in 2014 or 2013.

The Company evaluates the recoverability of its long-lived assets whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable (a "triggering event"). During the first quarter of 2015, oil prices averaged $48.54 per barrel and reached a low of $43.39 per barrel in March 2015. Oil prices improved during the second quarter of 2015 and averaged $57.85 per barrel. Although the price improvement was earlier than the Company projected, this improvement was generally consistent with the Company's assumption at December 31, 2014 that oil prices would improve late in 2015 and continue to improve in 2016, resulting in improved activity levels for both the contract drilling and pressure pumping businesses. During the second quarter of 2015 as oil prices increased, the Company received requests from customers to reactivate drilling rigs to resume operations in the third quarter of 2015. The Company believed this was an indication that future activity levels would be improving for both the contract drilling and pressure pumping businesses. During the third quarter of 2015, however, oil prices declined and averaged $46.42 per barrel and reached a new low for 2015 of $38.22 per barrel in August 2015.

With lower oil prices in August, the Company lowered its expectations with respect to future activity levels in both the contract drilling and pressure pumping businesses. In light of these revised expectations of the duration of the lower oil and natural gas commodity price environment and the related deterioration of the markets for contract drilling and pressure pumping services during the third quarter of 2015, management deemed it necessary to assess the recoverability of long-lived asset groups for both contract drilling and pressure pumping. The Company performed a Step 1 analysis as required by ASC 360-10-35 to assess the recoverability of long-lived assets within its contract drilling and pressure pumping segments. With respect to these assets, future cash flows were estimated over the expected remaining life of the assets, and the Company determined that, on an undiscounted basis, expected cash flows exceeded the carrying value of the long-lived assets, and no impairment was indicated. Expected cash flows, on an undiscounted basis, exceeded the carrying values of the long-lived assets within the contract drilling and pressure pumping segments by approximately 120% and 60%, respectively.

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

For both of the assessments performed in 2015, the expected cash flows for the contract drilling segment included the backlog of commitments for contract drilling revenues under term contracts, which was approximately $801 million and $710 million at September 30, 2015 and December 31, 2015, respectively. Rigs not under term contracts will be subject to pricing in the spot market. Utilization and rates for rigs in the spot market and for the pressure pumping segment were estimated based upon the

Company's historical experience in prior downturns. Also, the expected cash flows for the contract drilling and pressure pumping segments were based on the assumption that activity levels in both segments would begin to recover in the first quarter of 2017 in response to improved oil prices. While management believes these assumptions with respect to future pricing for oil and natural gas are reasonable, actual future prices may vary significantly from the ones that were assumed. The timeframe over which oil and natural gas prices will recover is highly uncertain. Potential events that could affect the Company's assumptions regarding future prices and the timeframe for a recovery are affected by factors such as:

- market supply and demand,
- the desire and ability of the Organization of Petroleum Exporting Countries, commonly known as OPEC, to set and maintain production and price targets,
- the level of production by OPEC and non-OPEC countries,
- domestic and international military, political, economic and weather conditions,
- legal and other limitations or restrictions on exportation and/or importation of oil and natural gas,
- technical advances affecting energy consumption and production,
- the price and availability of alternative fuels,
- the cost of exploring for, developing, producing and delivering oil and natural gas, and
- regulations regarding the exploration,

development, production and delivery of oil and natural gas.

All of these factors are beyond the Company's control. If the current lower oil and natural gas commodity price environment were to last into 2017 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.

With respect to the long-lived assets in the Company's oil and natural gas exploration and production segment, the Company assessed the recoverability of long-lived assets each quarter due to revisions in oil and natural gas reserve estimates and expectations about future commodity prices. The Company's analysis indicated that the carrying amounts of certain oil and natural gas properties were not recoverable at various testing dates in 2015. The Company's estimates of expected future net cash flows from impaired properties are used in measuring the fair value of such properties. The Company recorded impairment charges of $10.7 million in 2015 related to our oil and natural gas properties.

4. Goodwill and Intangible Assets

Goodwill — Goodwill by operating segment as of December 31, 2015 and 2014 and changes for the years then ended are as follows (in thousands):

	Contract Drilling	Pressure Pumping	Total
Balance December 31, 2013	$86,234	$67,575	$153,809
Changes to goodwill	—	56,986	56,986
Balance December 31, 2014	86,234	124,561	210,795
Changes to goodwill	—	(124,561)	(124,561)
Balance December 31, 2015	$86,234	$—	$86,234

There were no accumulated impairment losses related to goodwill in the contract drilling operating segment as of December 31, 2015 or 2014.

Goodwill is evaluated at least annually as of December 31, or when circumstances require, to determine if the fair value of recorded goodwill has decreased below its carrying value. For purposes of impairment testing, goodwill is evaluated at the reporting unit level. The Company's reporting units for impairment testing have been determined to be its operating segments. The Company first 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 it is, then goodwill impairment is determined using a two-step quantitative impairment test. From time to time, the Company may perform the first step of the quantitative testing for goodwill impairment in lieu of performing the qualitative assessment. The first step of the quantitative testing is to compare the fair value of an entity's reporting units to the respective carrying value of those reporting units. If the carrying value of a reporting unit exceeds its fair value, the second step of the quantitative testing is performed whereby the fair value of the reporting unit is allocated to its identifiable tangible and intangible assets and liabilities with any remaining fair value representing the fair value of goodwill. If this resulting fair value of goodwill is less than the carrying value of goodwill, an impairment loss would be recognized in the amount of the shortfall.

During the first quarter of 2015, oil prices averaged $48.54 per barrel and reached a low of $43.39 per barrel in March 2015. Oil prices improved during the second quarter of 2015 and averaged $57.85 per barrel. Although the price improvement was earlier than the Company projected, this improvement was generally consistent with the Company's assumption at December 31, 2014, that oil prices would improve in late 2015 and continue to improve in 2016, resulting in improved activity levels for both the contract drilling and pressure pumping businesses. During the second quarter of 2015 as oil prices increased, the Company received requests from customers to reactivate drilling rigs to resume operations in the third quarter of 2015. The Company believed this was an indication that future activity levels would be improving for both the contract drilling and pressure pumping businesses. During the third quarter of 2015, however, oil prices declined and averaged $46.42 per barrel and reached a new low for 2015 of $38.22 per barrel in August 2015. With lower oil prices in August, the Company lowered its expectations with respect to future activity levels in both the contract drilling and pressure pumping businesses. In light of the Company's revised expectations of the duration of the lower oil and natural gas commodity price environment and the related deterioration of the markets for contract drilling and pressure pumping services during the third quarter of 2015, the Company performed a quantitative impairment assessment of its goodwill as of September 30, 2015. In completing the first step of the assessment, the fair value of each reporting unit was estimated using both the income and market valuation methods. The estimate of the fair value of each reporting unit required the use of significant unobservable inputs, representative of a Level 3 fair value measurement. The inputs included assumptions related to the future performance of the Company's contract drilling and pressure pumping reporting units, such as future oil and natural gas prices and projected demand for the Company's services, and assumptions related to discount rates, long-term growth rates and control premiums.

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

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

In connection with its annual goodwill impairment assessment as of December 31, 2014, the Company determined based on an assessment of qualitative factors that it was more likely than not that the fair values of the Company's reporting units were greater than their carrying amounts and further testing was not necessary. In making this determination, the Company considered the continued demand experienced during 2014 for its services in the contract drilling and pressure pumping businesses. The Company also considered the current and expected levels of commodity prices for oil and natural gas, which influence its overall level of business activity in these operating segments. Additionally, operating results for 2014 and forecasted operating results for 2015 were also taken into account. The Company's overall market capitalization and the large amount of calculated excess of the fair values of the Company's reporting units over their carrying values from its 2013 quantitative impairment assessment were also considered.

The Company has undertaken extensive efforts in the past several years to upgrade its fleet of equipment and believes that it is well positioned from a competitive standpoint to satisfy demand for high technology drilling of unconventional horizontal wells, which should help mitigate decreases in demand for drilling conventional vertical wells that has resulted primarily from currently low oil and natural gas prices. In the event that market conditions were to remain weak for a protracted period, the Company may be required to record an impairment of goodwill in its contract drilling reporting unit in the future, and such impairment could be material.

Intangible Assets — Intangible assets were recorded in the pressure pumping operating segment in connection with the fourth quarter 2010 acquisition of the assets of a pressure pumping business. As a result of the purchase price allocation, the Company recorded intangible assets related to a non-compete agreement and the customer relationships acquired. These intangible assets were recorded at fair value on the date of acquisition.

The non-compete agreement had a term of three years from October 1, 2010. The value of this agreement was estimated using a with and without scenario where cash flows were projected through the term of the agreement assuming the agreement is in place and compared to cash flows assuming the non-compete agreement was not in place. The intangible asset associated with the non-compete agreement was amortized on a straight-line basis over the three-year term of the agreement. Amortization expense of $350,000 was recorded in the year ended December 31, 2013 associated with the non-compete agreement. The non-compete agreement expired in 2013.

The value of the customer relationships was estimated using a multi-period excess earnings model to determine the present value of the projected cash flows associated with the customers in place at the time of the acquisition and taking into account a contributory asset charge. The resulting intangible asset is being amortized on a straight-line basis over seven years. Amortization expense of $3.6 million was recorded in each of the years ended December 31, 2015, 2014 and 2013, associated with customer relationships.

The Company concluded no triggering events necessitating an impairment assessment of the non-compete agreement had occurred in 2013. The Company concluded no triggering events necessitating an impairment assessment of the customer relationships had occurred in 2014 or 2013. The assessment of the recoverability of the pressure pumping asset group included the customer relationship intangible asset, and no impairment was indicated.

The following table presents the gross carrying amount and accumulated amortization of the customer relationships as of December 31, 2015 and 2014 (in thousands):

	2015 Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	2014 Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Customer relationships	$25,500	$ (19,125)	$ 6,375	$25,500	$ (15,482)	$ 10,018

5. Accrued Expenses

Accrued expenses consisted of the following at December 31, 2015 and 2014 (in thousands):

	2015	2014
Salaries, wages, payroll taxes and benefits	$27,055	$52,956
Workers' compensation liability	75,358	77,348
Property, sales, use and other taxes	9,061	11,644
Insurance, other than workers' compensation	12,817	9,632
Accrued interest payable	7,668	7,427
Other	29,652	14,459
	$161,611	$173,466

6. Asset Retirement Obligation

The Company records a liability for the estimated costs to be incurred in connection with the abandonment of oil and natural gas properties in the future. This liability is included in the caption "other" in the liabilities section of the consolidated balance sheet.

The following table describes the changes to the Company's asset retirement obligations during 2015 and 2014 (in thousands):

	2015	2014
Balance at beginning of year	$5,301	$4,837
Liabilities incurred	340	473
Liabilities settled	(120)	(197)
Accretion expense	171	169
Revision in estimated costs of plugging oil and natural gas wells	—	19
Asset retirement obligation at end of year	$5,692	$5,301

7. Long-Term Debt

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

The revolving credit facility permits aggregate borrowings of up to $500 million outstanding at any time. The revolving credit facility contains a letter of credit facility that is limited to $150 million and a swing line facility that is limited to $40 million, in each case outstanding at any time.

The term loan facility provides for a loan of $100 million, which was drawn on December 24, 2012. The term loan facility is payable in quarterly principal installments, which commenced December 27, 2012. The installment amounts vary from 1.25% of the original principal amount for each of the first four quarterly installments, 2.50% of the original principal amount for each of the subsequent eight quarterly installments, 5.00% of the original principal amount for the subsequent four quarterly installments and 13.75% of the original principal amount for the final four quarterly installments.

Subject to customary conditions, the Company may request that the lenders' aggregate commitments with respect to the revolving credit facility and/or the term loan facility be increased by up to $100 million, not to exceed total commitments of $700 million. The maturity date under the Credit Agreement is September 27, 2017 for both the revolving facility and the term facility.

Loans under the Credit Agreement bear interest by reference, at the Company's election, to the LIBOR rate or base rate, provided, that swing line loans bear interest by reference only to the base rate. The applicable margin on LIBOR rate loans varies from 2.25% to 3.25% and the applicable margin on base rate loans varies from 1.25% to 2.25%, in each case determined based upon the Company's debt to capitalization ratio. At December 31, 2015, the applicable margin on LIBOR rate loans was 2.25% and the applicable margin on base rate loans was 1.25%. Based on the Company's debt to capitalization ratio at September 30, 2015, the applicable margin on LIBOR rate loans is 2.25% and the applicable margin on base rate loans is 1.25% as of January 1, 2016. Based on the Company's debt to capitalization ratio at December 31, 2015, the applicable margin on LIBOR rate loans will be 2.75% and the applicable margin on base rate loans will be 1.75% as of April 1, 2016. A letter of credit fee is payable by the Company equal to the applicable margin for LIBOR rate loans times the amount available to be drawn under outstanding letters of credit. The commitment fee rate payable to the lenders for the unused portion of the credit facility is 0.50%.

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

The Credit Agreement requires compliance with two financial covenants. The Company must not permit its debt to capitalization ratio to exceed 45%. The Credit Agreement generally defines the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. The Company also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 3.00 to 1.00. The Credit Agreement generally defines the interest coverage ratio as the ratio of earnings before interest, taxes, depreciation and amortization ("EBITDA") of the four prior fiscal quarters to interest charges for the same period. The Company was in compliance with these covenants at December 31, 2015. The Credit Agreement also contains customary representations, warranties and affirmative and negative covenants.

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

As of December 31, 2015, the Company had $70.0 million principal amount outstanding under the term loan facility at an interest rate of 2.875% and no amounts outstanding under the revolving credit facility. The Company currently has available borrowing capacity of $500 million under the revolving credit facility.

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, 2015, the Company had $41.1 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.

2015 Term Loan Agreement — On March 18, 2015, the Company entered into a Term Loan Agreement (the "2015 Term Loan Agreement") with Wells Fargo Bank, N.A., as administrative agent and lender, each of the other lenders party thereto, Wells Fargo Securities, LLC, as Lead Arranger and Sole Book Runner, and Bank of America, N.A. and The Bank Of Tokyo-Mitsubishi UFJ, LTD., as Co-Syndication Agents.

The 2015 Term Loan Agreement is a senior unsecured single-advance term loan facility pursuant to which the Company made a term loan borrowing of $200 million on March 18, 2015 (the "Term Loan Borrowing"). The Term Loan Borrowing is payable in quarterly principal installments, together with accrued interest, on each June 30, September 30, December 31 and March 31, commencing on June 30, 2015. Each of the first four principal installments is in an amount equal to 2.5% of the Term Loan Borrowing and each successive quarterly installment, until and including June 30, 2017, is in an amount equal to 5.0% of the Term Loan Borrowing, with the outstanding principal balance of the Term Loan Borrowing due on the maturity date under the 2015 Term Loan Agreement. The maturity date under the 2015 Term Loan Agreement is September 27, 2017. Loans under the 2015 Term Loan Agreement bear interest, at the Company's election, at the per annum rate of LIBOR rate plus 3.25% or base rate plus 2.25%.

Each domestic subsidiary of the Company will unconditionally guarantee all existing and future indebtedness and liabilities of the other guarantors and the Company arising under the 2015 Term Loan Agreement and other Loan Documents (as defined in the 2015 Term Loan Agreement), other than (a) Ambar Lone Star Fluid Services LLC, (b) domestic subsidiaries that directly or indirectly have no material assets other than equity interests in, or capitalization indebtedness owed by, foreign subsidiaries, and (c) any subsidiary having total assets of less than $1 million.

The 2015 Term Loan Agreement requires quarterly compliance with two financial covenants. The Company must not permit its debt to capitalization ratio to exceed 45%. The 2015 Term Loan 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 most recently ended fiscal quarter. The Company also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 3.00 to 1.00. The 2015 Term Loan Agreement generally defines the interest coverage ratio as the ratio of EBITDA of the four prior fiscal quarters to interest charges for the same period. The Company was in compliance with these covenants at December 31, 2015.

The 2015 Term Loan Agreement further provides that neither the Company nor its subsidiaries is permitted to make restricted payments unless, after giving effect to such restricted payment, its pro forma ratio of debt to EBITDA for the four prior fiscal quarters, determined as of the preceding ending quarterly period, does not exceed 2.50 to 1.00. Restricted payments are generally defined as (a) dividends and distributions made on account of equity interests of the Company or its subsidiaries and (b) payments made to redeem, repurchase or otherwise retire equity interests of the Company or its subsidiaries. Payments made solely in the form of common equity interests, made to the Company and its subsidiaries, or made in connection with the Company's long-term incentive plans are not restricted payments under the 2015 Term Loan Agreement.

The 2015 Term Loan Agreement also contains customary representations, warranties, affirmative and negative covenants, and events of default. Events of default under the 2015 Term Loan Agreement include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, as well as a cross default event, Loan Document enforceability event, change of control event and bankruptcy and other insolvency events. If an event of default occurs and is continuing, then a majority of the lenders have the right, among others, to accelerate and require the Company to repay all the outstanding amounts owed under any Loan Document (provided that in limited circumstances with respect to insolvency and bankruptcy of the Company, such acceleration is automatic).

As of December 31, 2015, the Company had $185 million principal amount outstanding under the 2015 Term Loan Agreement at a rate of 3.875%.

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

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

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

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

The respective note purchase agreements require compliance with two financial covenants. The Company must not permit its debt to capitalization ratio to exceed 50% at any time. The note purchase agreements generally define the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. The Company also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 2.50 to 1.00. The note purchase agreements generally define the interest coverage ratio as the ratio of EBITDA for the four prior fiscal quarters to interest charges for the same period. The Company was in compliance with these covenants at December 31, 2015.

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

The Company incurred approximately $10.8 million in debt issuance costs during 2010 in connection with the Series A Notes and a previous senior unsecured revolving credit facility. The Company incurred approximately $7.6 million in debt issuance costs during 2012 in connection with the Series B Notes and the Credit Agreement. The Company incurred approximately $2.0 million in debt issuance costs during 2015 in connection with the Reimbursement Agreement and the 2015 Term Loan Agreement. These costs were deferred and are recognized as interest expense over the term of the underlying debt. Interest expense related to the amortization of debt issuance costs was approximately $2.8 million, $2.2 million and $2.2 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Presented below is a schedule of the principal repayment requirements of long-term debt by fiscal year as of December 31, 2015 (in thousands):

Year ending December 31,	
2016	$63,750
2017	191,250
2018	—
2019	—
2020	300,000
Thereafter	300,000
Total	$855,000

8. Commitments, Contingencies and Other Matters

Commitments – As of December 31, 2015, the Company maintained letters of credit in the aggregate amount of $41.1 million for the benefit of various insurance companies as collateral for retrospective premiums and retained losses which could become payable under the terms of the underlying insurance contracts. These letters of credit expire annually at various times during the year and are typically renewed. As of December 31, 2015, no amounts had been drawn under the letters of credit.

As of December 31, 2015, the Company had commitments to purchase approximately $73.5 million of major equipment for its drilling and pressure pumping businesses.

The Company’s pressure pumping business has entered into agreements to purchase minimum quantities of proppants and chemicals from certain vendors. These agreements expire in 2016, 2017 and 2018. As of December 31, 2015, the remaining obligation under these agreements was approximately $26.5 million, of which materials with a total purchase price of approximately $9.5 million are required to be purchased during 2016. In the event that the required minimum quantities are not purchased during any contract year, the Company could be required to make a liquidated damages payment to the respective vendor for any shortfall.

In November 2011, the Company’s pressure pumping business entered into an agreement with a proppant vendor to advance up to $12.0 million to such vendor to finance the construction of certain processing facilities. This advance is secured by the underlying processing facilities and bears interest at an annual rate of 5.0%. Repayment of the advance is to be made through discounts applied to purchases from the vendor and repayment of all amounts advanced must be made no later than October 1, 2017. As of December 31, 2015, advances of approximately $11.8 million had been made under this agreement and repayments of approximately $10.6 million had been received resulting in a balance outstanding of approximately $1.2 million.

Contingencies – A $12.3 million charge related to the previously disclosed settlement of a lawsuit filed by the U.S. Equal Employment Opportunity Commission against the Company’s U.S. contract drilling subsidiary was recorded in 2015.

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

Any contractual right to indemnification that the Company may have for any such risk, may be unenforceable or limited due to negligent or willful acts of commission or omission by the Company, its subcontractors and/or suppliers. The Company's customers and other third parties may dispute, or be unable to meet, their contractual indemnification obligations to the Company due to financial, legal or other reasons. Accordingly, the Company may be unable to transfer these risks to its customers and other third parties by contract or indemnification agreements. Incurring a liability for which the Company is not fully indemnified or insured could have a material adverse effect on its business, financial condition, cash flows and results of operations.

The Company has insurance coverage for fire, windstorm and other risks of physical loss to its rigs and certain other assets, employer's liability, automobile liability, commercial general liability, workers' compensation and insurance for other specific risks. The Company has also elected in some cases to accept a greater amount of risk through increased deductibles on certain insurance policies. For example, the Company generally maintains a $1.5 million per occurrence deductible on its workers' compensation insurance coverage, a $1.0 million per occurrence deductible on its equipment insurance coverage, a $2.0 million per occurrence self-insured retention on its general liability coverage and a $2.0 million per occurrence deductible on its automobile liability insurance coverage. The Company self-insures a number of other risks, including loss of earnings and business interruption, and does not carry a significant amount of insurance to cover risks of underground reservoir damage. 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 the Company's business, financial condition, cash flows and results of operations. Accrued expenses related to insurance claims are set forth in Note 5.

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

Other Matters — The Company has Change in Control Agreements with its Chairman of the Board, Chief Executive Officer, two Senior Vice Presidents and its General Counsel (the "Key Employees"). Each Change in Control Agreement generally has an initial term with automatic twelve-month renewals unless the Company notifies the Key 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 Key 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 Key Employee for good reason (as those terms are defined in the Change in Control Agreements), then the Key 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 Key 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 and Chief Executive Officer), 2 times (in the case of the Senior Vice Presidents) or 1.5 times (in the case of the General Counsel) of the sum of (i) the highest annual salary in effect for such Key Employee and (ii) the average of the three annual bonuses earned by the Key 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 and Chief Executive Officer) or two years (in the case of the Senior Vice Presidents and General Counsel).

Other than with respect to the Chief Executive Officer, each Change in Control Agreement provides the Key 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.

9. Stockholders' Equity

Cash Dividends – The Company paid cash dividends during the years ended December 31, 2013, 2014 and 2015 as follows:

	Per Share	Total (in thousands)
2013:		
Paid on March 29, 2013	$0.05	$ 7,312
Paid on June 28, 2013	0.05	7,361
Paid on September 30, 2013	0.05	7,231
Paid on December 31, 2013	0.05	7,208
Total cash dividends	$0.20	$ 29,112

2014:		
Paid on March 27, 2014	$ 0.10	$ 14,456
Paid on June 26, 2014	0.10	14,562
Paid on September 24, 2014	0.10	14,634
Paid on December 24, 2014	0.10	14,636
Total cash dividends	$ 0.40	$ 58,288
2015:		
Paid on March 25, 2015	$ 0.10	$ 14,640
Paid on June 24, 2015	0.10	14,712
Paid on September 24, 2015	0.10	14,712
Paid on December 24, 2015	0.10	14,711
Total cash dividends	$ 0.40	$ 58,775

On February 3, 2016, the Company’s Board of Directors approved a cash dividend on its common stock in the amount of $0.10 per share to be paid on March 24, 2016 to holders of record as of March 10, 2016. The Company’s 2015 Term Loan Agreement contains a covenant that could restrict its ability to make dividend payments later in 2016. 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 July 25, 2012, the Company's Board of Directors approved a stock buyback program authorizing purchases of up to $150 million of common stock in open market or privately negotiated transactions. On September 6, 2013, the Company's Board of Directors terminated any remaining authority under the 2012 stock buyback program, and approved a new stock buyback program that authorizes purchase of up to $200 million of the Company's common stock in open market or privately negotiated transactions. As of December 31, 2015, the Company had remaining authorization to purchase approximately $187 million of the Company's outstanding common stock under the 2013 stock buyback program. Shares purchased under a buyback program are accounted for as treasury stock.

The Company acquired shares of stock from employees during 2015, 2014 and 2013 that are accounted for as treasury stock. Certain of these shares were acquired to satisfy the exercise price in connection with the exercise of stock options by employees. The remainder of these shares was acquired to satisfy payroll tax withholding obligations upon the exercise of stock options, the settlement of performance unit awards and the vesting of restricted stock. These shares were acquired at fair market value. These acquisitions were made pursuant to the terms of the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (the "2005 Plan") or the Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan (the "2014 Plan") and not pursuant to the stock buyback programs.

Treasury stock acquisitions during the years ended December 31, 2015, 2014 and 2013 were as follows (dollars in thousands):

	2015		2014		2013	
	Shares	Cost	Shares	Cost	Shares	Cost
Treasury shares at beginning of period	42,818,585	$899,035	42,268,057	$880,888	38,146,738	$795,051
Purchases pursuant to stock buyback programs:						
2012 program	—	—	—	—	2,567,266	51,107
2013 program	8,618	180	13,898	466	602,564	12,517
Acquisitions pursuant to long-term incentive plans	380,037	7,830	536,630	17,681	951,489	22,213
Treasury shares at end of period	43,207,240	$907,045	42,818,585	$899,035	42,268,057	$880,888

10. Stock-based Compensation

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

The Company's shareholders have approved the 2014 Plan, and the Board of Directors adopted a resolution that no future grants would be made under any of the Company's other previously existing plans. The Company's share-based compensation plans at December 31, 2015 follow:

Plan Name	Shares Authorized for Grant	Shares Underlying Awards Outstanding	Shares Available for Grant
Patterson-UTI Energy, Inc. 2014 Long-Term Incentive Plan	9,100,000	2,509,623	4,018,824
Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, as amended	—	5,271,563	—

A summary of the 2014 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, 2015, non-incentive stock options, restricted stock awards, restricted stock units and performance unit awards had been granted under the plan.

Options granted under the 2005 Plan typically vested over one year for non-employee directors and three years for employees. All options were granted with an exercise price equal to the fair market value of the related common stock at the time of grant. Restricted stock awards granted under the 2005 Plan typically vested over one year for non-employee directors and three years for employees.

Stock Options—The Company estimates the grant date fair values of stock options using the Black-Scholes-Merton valuation model. Volatility assumptions are based on the historic volatility of the Company's common stock over the most recent period equal to the expected term of the options as of the date the options are granted. The expected term assumptions are based on the Company's experience with respect to employee stock option activity. Dividend yield assumptions are based on the expected dividends at the time the options are granted. The risk-free interest rate assumptions are determined by reference to United States Treasury yields. Weighted-average assumptions used to estimate grant date fair values for stock options granted in the years ended December 31, 2015, 2014 and 2013 follow:

	2015	2014	2013
Volatility	37.95%	35.89%	41.36%
Expected term (in years)	5.00	5.00	5.00
Dividend yield	2.00 %	1.17 %	0.89 %
Risk-free interest rate	1.37 %	1.76 %	0.70 %

Stock option activity for the year ended December 31, 2015 follows:

	Shares	Weighted-average exercise price
Outstanding at beginning of year	6,086,250	$ 22.32
Granted	831,000	$ 20.06
Exercised	—	—
Cancelled	(10,000)	$ 16.59
Expired	(600,000)	$ 26.06
Outstanding at end of year	6,307,250	$ 21.68
Exercisable at end of year	5,224,082	$ 21.49

Options outstanding at December 31, 2015 have an aggregate intrinsic value of approximately $1.7 million and a weighted-average remaining contractual term of 4.99 years. Options exercisable at December 31, 2015 have an aggregate intrinsic value of approximately $1.7 million and a weighted-average remaining contractual term of 4.16 years. Additional information with respect to options granted, vested and exercised during the years ended December 31, 2015, 2014 and 2013 follows:

	2015	2014	2013
Weighted-average grant date fair value of stock options granted (per share)	$5.79	$9.81	$7.59

Aggregate grant date fair value of stock options vested during the year (in thousands)	$5,077	$5,173	$5,240
Aggregate intrinsic value of stock options exercised (in thousands)	$—	$21,862	$8,683

As of December 31, 2015, options to purchase 1.1 million shares were outstanding and not vested. All of these non-vested options are expected to ultimately vest. Additional information as of December 31, 2015 with respect to these non-vested options follows:

Aggregate intrinsic value (in thousands)	$ —
Weighted-average remaining contractual term	8.99 years
Weighted-average remaining expected term	3.99 years
Weighted-average remaining vesting period	1.89 years
Unrecognized compensation cost	$5.8 million

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

Restricted stock activity for the year ended December 31, 2015 follows:

	Shares	Weighted-average Grant Date Fair Value
Non-vested restricted stock outstanding at beginning of year	1,493,059	$ 26.93
Granted	795,600	$ 20.58
Vested	(774,235)	$ 24.89
Forfeited	(82,174)	$ 25.89
Non-vested restricted stock outstanding at end of year	1,432,250	$ 24.56

As of December 31, 2015, approximately 1.3 million shares of non-vested restricted stock outstanding are expected to vest. Additional information as of December 31, 2015 with respect to these non-vested shares follows:

Aggregate intrinsic value	$19.9 million
Weighted-average remaining vesting period	1.8 years
Unrecognized compensation cost	$25.1 million

Restricted Stock Units—For all restricted stock unit awards made to date, shares of common stock are not issued until the units vest. Restricted stock units are subject to forfeiture for failure to fulfill service conditions. Non-forfeitable cash dividend equivalents are paid on certain non-vested restricted stock units. 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, 2015 follows:

	Shares	Weighted-average Grant Date Fair Value
Non-vested restricted stock units outstanding at beginning of year	34,085	$ 30.20
Granted	22,100	$ 20.85
Vested	(14,499)	$ 27.37
Forfeited	—	$ —
Non-vested restricted stock units outstanding at end of year	41,686	$ 26.22

Performance Unit Awards. Each year, beginning in 2010, the Company granted stock-settled performance unit awards to certain executive officers (the "Stock-Settled Performance Units"). The Stock-Settled Performance Units provide for the recipients to receive a grant of shares of stock upon the achievement of certain performance goals established by the Compensation Committee during a specified period. The performance period for the Stock-Settled Performance Units is the three year period commencing on April 1 of the year of grant. For the 2012 and 2013 Stock-Settled Performance Units, the performance period can extend for an additional two years in certain circumstances. The performance goals for the Stock-Settled Performance Units are tied to the Company's total shareholder return for the performance period as compared to total shareholder return for a peer group determined by the Compensation Committee. These goals are considered to be market conditions under the relevant accounting standards and the market conditions were factored into the determination of the fair value of the respective performance units. Generally, the recipients will receive a target number of shares if the Company's total shareholder return is positive and, when compared to the peer group, is at the 50^{th} percentile and two times the target if at the 75^{th} percentile or higher. If the Company's total shareholder return is positive, and, when compared to the peer group, is at the 25^{th} percentile, the recipients will only receive one-half of the target number of shares. The grant of shares when achievement is between the 25^{th} and 75^{th} percentile will be determined on a pro-rata basis. There is no payout unless the Company's total shareholder return is positive and, when compared to the peer group, is at or above the 25^{th} percentile. The total target number of shares with respect to the Stock-Settled Performance Units is set forth below:

	2015 Performance Unit Awards	2014 Performance Unit Awards	2013 Performance Unit Awards	2012 Performance Unit Awards	2011 Performance Unit Awards	2010 Performance Unit Awards
Target number of shares	190,600	154,000	236,500	192,000	144,375	178,750

F-23

For the stock-settled Performance Units that have been settled, following are the total shareholder return percentiles and the number of shares issued:

	2012 Performance Unit Awards	2011 Performance Unit Awards	2010 Performance Unit Awards
Total shareholder return percentile for performance period	87th	94th	93rd
Shares issued	384,000	288,750	357,500

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

	2015 Performance Unit Awards	2014 Performance Unit Awards	2013 Performance Unit Awards	2012 Performance Unit Awards	2011 Performance Unit Awards	2010 Performance Unit Awards
Aggregate fair value at date of grant	$ 4,052	$ 5,388	$ 5,564	$ 3,065	$ 5,569	$ 3,117

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

	2015 Performance Unit Awards	2014 Performance Unit Awards	2013 Performance Unit Awards	2012 Performance Unit Awards	2011 Performance Unit Awards	2010 Performance Unit Awards
Year ended December 31, 2015	$ 1,013	$ 1,796	$ 1,855	$ 255	NA	NA
Year ended December 31, 2014	NA	$ 1,347	$ 1,855	$ 1,022	$ 464	NA
Year ended December 31, 2013	NA	NA	$ 1,391	$ 1,022	$ 1,856	$ 260

Dividends on Equity Awards – Non-forfeitable cash dividends are paid on restricted stock awards and dividend equivalents are paid on certain restricted stock units. These payments 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 additional compensation cost for restricted stock units.

11. Leases

The Company incurred rent expense of $37.6 million, $51.9 million and $47.4 million for the years ended December 31, 2015, 2014 and 2013, respectively. Rent expense is primarily related to short-term equipment rentals that are generally passed through to customers.

Future minimum rental payments required under operating leases having initial or remaining non-cancelable lease terms in excess of one year at December 31, 2015 are as follows:

Year ending December 31,	
2016	$10,522
2017	4,969
2018	4,053
2019	3,229
2020	2,734
Thereafter	4,655
Total	$30,162

12. Income Taxes

Components of the income tax provision applicable to federal, state and foreign income taxes for the years ended December 31, 2015, 2014 and 2013 are as follows (in thousands):

	2015	2014	2013
Federal income tax expense (benefit):			
Current	$(42,020)	$39,438	$41,558
Deferred	(83,812)	39,673	47,136
	(125,832)	79,111	88,694
State income tax expense (benefit):			
Current	(3,480)	3,987	11,733
Deferred	(12,433)	5,292	4,229
	(15,913)	9,279	15,962
Foreign income tax expense (benefit):			
Current	(2,590)	4,521	4,572
Deferred	(3,628)	(1,292)	(796)
	(6,218)	3,229	3,776
Total income tax expense (benefit):			
Current	(48,090)	47,946	57,863
Deferred	(99,873)	43,673	50,569
Total income tax expense (benefit):	$(147,963)	$91,619	$108,432

The difference between the statutory federal income tax rate and the effective income tax rate for the years ended December 31, 2015, 2014 and 2013 is summarized as follows:

	2015	2014	2013
Statutory tax rate	35.0%	35.0%	35.0%
State income taxes	2.1	2.5	3.7
Permanent differences	(1.3)	(1.4)	(1.5)
Other differences, net	(2.4)	(0.1)	(0.6)
Effective tax rate	33.4%	36.0%	36.6%

The Domestic Production Activities Deduction (IRC section 199 deduction) was enacted as part of the American Jobs Creation Act of 2004 (as revised by the Emergency Economic Stabilization Act of 2008) and allows a deduction of 9% in 2010 and thereafter on the lesser of qualified production activities income or taxable income. The permanent differences for 2013 include a deduction of $10.0 million as the Company fully utilized its remaining net operating loss carryforwards. The permanent differences for 2014 include a deduction of $8.8 million. The permanent differences for 2015 do not include any deduction as it is limited to taxable income, and the Company did not have taxable income in 2015 as a result of the Company’s election to utilize bonus depreciation.

The 2015 other differences include a 1% reduction related to the reconciliation of the deferred tax liability associated with the conversion of the Company’s Canadian operations to a controlled foreign corporation. The impact to the deferred tax liability from the conversion is being amortized over the weighted average remaining useful life of the Canadian assets. The 2015 other differences also include a 0.7% reduction for the lost benefit of the 2014 IRC section 199 deduction of $8.8 million as a result of the Company's adoption of the final tangible property regulations with the filing of the 2014 tax return.

The tax effect of significant temporary differences representing deferred tax assets and liabilities and changes therein were as follows (in thousands):

	December 31, 2015	Net Change	December 31, 2014	Net Change	December 31, 2013	Net Change	December 31, 2012
Deferred tax assets:							
Current:							
Net operating loss carryforwards	$27,887	$27,887	$—	$—	$—	$(18,914)	$18,914
Workers' compensation allowance	28,734	424	28,310	698	27,612	2,534	25,078
Other	21,305	(1,091)	22,396	2,749	19,647	(804)	20,451
	77,926	27,220	50,706	3,447	47,259	(17,184)	64,443
Non-current:							
Net operating loss carryforwards	77,514	65,050	12,464	(988)	13,452	1,690	11,762
Expense associated with employee stock options	14,591	205	14,386	(1,822)	16,208	1,536	14,672
Federal benefit of state deferred tax liabilities	24,485	466	24,019	1,181	22,838	816	22,022
Other	20,441	4,394	16,047	1,344	14,703	(421)	15,124
	137,031	70,115	66,916	(285)	67,201	3,621	63,580
Less:							
Allowance to reduce deferred tax asset to expected realizable value	(603)	(603)	—	—	—	—	—
Total deferred tax assets	214,354	96,732	117,622	3,162	114,460	(13,563)	128,023
Deferred tax liabilities:							
Current:							
Other	(12,805)	826	(13,631)	676	(14,307)	(2,823)	(11,484)
Non-current:							
Property and equipment basis difference	(986,922)	31	(986,953)	(47,359)	(939,594)	(33,997)	(905,597)
Other	(13,339)	2,284	(15,623)	(152)	(15,471)	(186)	(15,285)
	(1,000,261)	2,315	(1,002,576)	(47,511)	(955,065)	(34,183)	(920,882)
Total deferred tax liabilities	(1,013,066)	3,141	(1,016,207)	(46,835)	(969,372)	(37,006)	(932,366)
Net deferred tax liability	$(798,712)	$99,873	$(898,585)	$(43,673)	$(854,912)	$(50,569)	$(804,343)

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized, and necessary allowances are provided. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. The Company expects the carrying value of the deferred tax assets at December 31, 2015 and 2014 to be realized as a result of the reversal of existing taxable temporary differences giving rise to deferred tax liabilities and the generation of taxable income. The valuation allowance of $603,000 is related to state net operating losses being carried forward that will expire in 2016.

Other deferred tax assets consist primarily of the tax effect of various allowance accounts and tax-deferred expenses expected to generate future tax benefits of approximately $41.7 million. Other deferred tax liabilities consist primarily of the tax effect of receivables from insurance companies and tax-deferred income not yet recognized for tax purposes.

For income tax purposes, the Company has approximately $257 million of federal net operating losses and approximately $237 million, net of valuation allowance, of state net operating losses as of December 31, 2015. Of these amounts, approximately $111 million will be carried back to prior years and the remaining balance can be carried forward to future years. Net operating losses that can be carried forward, if unused, are scheduled to expire as follows: 2025—$2.8 million; 2026—$17.1 million; 2027—$75,000; 2029—$33.2 million; 2030—$27.5 million; 2031—$88.0 million; 2034—$2,000; 2035—$213.9 million.

As of December 31, 2015, 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, 2015, the tax years ended December 31, 2012 through December 31, 2014 are open for examination by U.S. taxing authorities. As of December 31, 2015, the tax years ended December 31, 2011 through December 31, 2014 are open for examination by Canadian taxing authorities.

On January 1, 2010, the Company converted its Canadian operations from a Canadian branch to a controlled foreign corporation for federal income tax purposes. This transaction triggered a $1.0 million increase in deferred tax liabilities, which is being amortized as an increase to deferred income tax expense over the weighted average remaining useful life of the Canadian assets. This will be fully amortized by December 31, 2016.

As a result of the above conversion, the Company's Canadian assets are no longer directly subject to United States taxation, provided that the related unremitted earnings are permanently reinvested in Canada. Effective January 1, 2010, the Company has elected to permanently reinvest these unremitted earnings in Canada, and intends to do so for the foreseeable future. As a result, no deferred United States federal or state income taxes have been provided on such unremitted foreign earnings, which totaled approximately $28.4 million as of December 31, 2015. The unrecognized deferred tax liability associated with these earnings was approximately $3.8 million, net of available foreign tax credits. This liability would be recognized if the Company received a dividend of the unremitted earnings.

13. Employee Benefits

The Company maintains a 401(k) plan for all eligible employees. The Company's operating results include expenses of approximately $7.1 million in 2015, $7.2 million in 2014 and $6.2 million in 2013 for the Company's contributions to the plan.

14. Business Segments

The Company's revenues, operating profits and identifiable assets are primarily attributable to three business segments: (i) contract drilling of oil and natural gas wells, (ii) pressure pumping services and (iii) the investment, on a non-operating working interest basis, in oil and natural gas properties. Each of these segments represents a distinct type of business. These segments have separate management teams which report to the Company's chief operating decision maker. The results of operations in these segments are regularly reviewed by the chief operating decision maker for purposes of determining resource allocation and assessing performance.

Contract Drilling — The Company markets its contract drilling services to major and independent oil and natural gas operators. As of December 31, 2015, the Company had 221 land-based drilling rigs in the continental United States and western Canada.

For the years ended December 31, 2015, 2014 and, 2013, contract drilling revenue earned in Canada was $37.5 million, $87.5 million and $86.6 million, respectively. Additionally, long-lived assets within the contract drilling segment located in Canada totaled $53.4 million and $57.6 million as of December 31, 2015 and 2014, respectively.

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

Oil and Natural Gas — The Company owns and invests in oil and natural gas assets as a non-operating working interest owner. The Company's oil and natural gas interests are located primarily in Texas and New Mexico.

Major Customer — During 2015, one customer accounted for approximately $244 million or 13% of the Company's consolidated operating revenues. These revenues were earned in both the Company's contract drilling and pressure pumping businesses. During 2014, no single customer accounted for more than 10% of consolidated operating revenue. During 2013, one customer accounted for approximately $286 million or 10.5% of the Company's consolidated operating revenues. These revenues were earned in both the Company's contract drilling and pressure pumping businesses.

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

	Years Ended December 31,		
	2015	2014	2013
Revenues:			
Contract drilling	$1,155,565	$1,843,707	$1,684,878
Pressure pumping	712,454	1,294,569	979,166
Oil and natural gas	24,931	50,196	57,257
Total segment revenues	1,892,950	3,188,472	2,721,301
Elimination of intercompany revenues(a)	(1,673)	(6,181)	(5,267)
Total revenues	$1,891,277	$3,182,291	$2,716,034
Income (loss) before income taxes:			
Contract drilling	$(91,230)	$241,851	$266,262
Pressure pumping	(254,998)	89,081	87,244
Oil and natural gas	(12,870)	(5,482)	19,948
	(359,098)	325,450	373,454
Corporate and other	(58,487)	(58,105)	(54,647)
Net gain on asset disposals(b)	10,613	15,781	3,384
Interest income	964	979	918
Interest expense	(36,475)	(29,825)	(28,359)
Other	34	3	1,691
Income (loss) before income taxes	$(442,449)	$254,283	$296,441
Identifiable assets:			
Contract drilling	$3,457,044	$4,000,576	$3,569,588
Pressure pumping	813,704	1,186,010	761,199
Oil and natural gas	34,073	50,945	58,656
Corporate and other(c)	228,496	156,480	297,684
Total assets	$4,533,317	$5,394,011	$4,687,127
Depreciation, depletion, amortization and impairment:			
Contract drilling	$618,434	$524,023	$438,728
Pressure pumping	214,552	147,595	129,984
Oil and natural gas	26,301	42,576	24,400
Corporate and other	5,472	4,536	4,357
Total depreciation, depletion, amortization and impairment	$864,759	$718,730	$597,469
Capital expenditures:			
Contract drilling	$527,054	$771,593	$504,508
Pressure pumping	197,577	241,359	122,782
Oil and natural gas	16,625	36,683	31,245
Corporate and other	2,520	2,706	3,926
Total capital expenditures	$743,776	$1,052,341	$662,461

(a) Consists of contract drilling and, in 2014, pressure pumping intercompany revenues for services provided to the oil and natural gas exploration and production segment.

(b) Net gains or losses associated with the disposal of assets relate to corporate strategy decisions of the executive management group. Accordingly, the related gains or losses have been separately presented and excluded from the results of specific segments.

(c) Corporate and other assets primarily include cash on hand, income tax receivables and certain deferred tax assets.

15. Concentrations of Credit Risk

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

The Company believes it has placed its demand deposits and temporary cash investments with high credit-quality financial institutions. At December 31, 2015 and 2014, the Company's demand deposits and temporary cash investments consisted of the following (in thousands):

	2015	2014
Deposits in FDIC and SIPC-insured institutions under insurance limits	$617	$636
Deposits in FDIC and SIPC-insured institutions over insurance limits	130,330	1,420
Deposits in foreign banks	15,303	43,664
	146,250	45,720
Less outstanding checks and other reconciling items	(32,904)	(2,708)
Cash and cash equivalents	$113,346	$43,012

Concentrations of credit risk with respect to trade receivables are primarily focused on companies involved in the exploration and development of oil and natural gas properties. The concentration is somewhat mitigated by the diversification of customers for which the Company provides services. As is general industry practice, the Company typically does not require customers to provide collateral. No significant losses from individual customers were experienced during the years ended December 31, 2015, 2014 or 2013. No provision for bad debts was recognized in 2015, 2014 or 2013.

16. Fair Values of Financial Instruments

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

The estimated fair value of the Company's outstanding debt balances (including current portion) as of December 31, 2015 and 2014 is set forth below (in thousands):

	December 31, 2015		December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Borrowings under Credit Agreement:				
Revolving credit facility	$—	$—	$303,000	$303,000
Term loan facility	70,000	70,000	82,500	82,500
2015 Term Loan	185,000	185,000	—	—
4.97% Series A Senior Notes	300,000	279,635	300,000	288,346
4.27% Series B Senior Notes	300,000	258,806	300,000	269,173
Total debt	$855,000	$793,441	$985,500	$943,019

The carrying values of the balances outstanding under the revolving credit facility, the term loan facility, and the 2015 Term Loan approximate their fair values as these instruments have floating interest rates. The fair values of the Series

A Notes and Series B Notes at December 31, 2015 and 2014 are based on discounted cash flows associated with the respective notes using current market rates of interest at those respective dates. For the Series A Notes, the current market rates used in measuring this fair value were 6.66% at December 31, 2015 and 5.77% at December 31, 2014. For the Series B Notes, the current market rates used in measuring this fair value were 6.95% at December 31, 2015 and 6.00% at December 31, 2014. These fair value estimates are based on observable market inputs and are considered Level 2 fair value estimates in the fair value hierarchy of fair value accounting.

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

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2014				
Operating revenues	$678,168	$757,276	$845,628	$901,219
Operating income	58,776	87,226	30,291	106,833
Net income	34,822	54,283	15,976	57,583
Net income per common share:				
Basic	$0.24	$0.37	$0.11	$0.39
Diluted	$0.24	$0.37	$0.11	$0.39
2015				
Operating revenues	$657,699	$472,761	$422,251	$338,566
Operating income (loss)	24,103	(24,764)	(329,515)	(76,796)
Net income (loss)	9,125	(18,975)	(225,978)	(58,658)
Net income (loss) per common share:				
Basic	$0.06	$(0.13)	$(1.54)	$(0.40)
Diluted	$0.06	$(0.13)	$(1.54)	$(0.40)

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, 2015				
Deducted from asset accounts:				
Allowance for doubtful accounts	$3,546	$ —	$ (1)	$3,545
Year Ended December 31, 2014				
Deducted from asset accounts:				
Allowance for doubtful accounts	$3,674	$ —	$ (128)	$3,546
Year Ended December 31, 2013				
Deducted from asset accounts:				
Allowance for doubtful accounts	$3,513	$ —	$ 161	$3,674

(1) Consists of uncollectible accounts (written off) or recovered.

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 10, 2016

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 10, 2016.

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 and Chief Executive Officer
/s/ John E. Vollmer III John E. Vollmer III (Principal Financial and Accounting Officer)	Senior Vice President — Corporate Development, Chief Financial Officer and Treasurer
/s/ Kenneth N. Berns Kenneth N. Berns	Senior Vice President and Director
/s/ Charles O. Buckner Charles O. Buckner	Director
/s/ Michael W. Conlon Michael W. Conlon	Director
/s/ Curtis W. Huff Curtis W. Huff	Director
/s/ Terry H. Hunt Terry H. Hunt	Director
/s/ Tiffany J. Thom Tiffany J. Thom	Director

EXHIBIT INDEX

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 for the quarterly period ended June 30, 2004 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 for the quarterly period ended June 30, 2004 and incorporated herein by reference).

3.3 Certificate of Elimination with respect to Series A Participating Preferred Stock (filed October 27, 2011 as Exhibit 3.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

3.4 Second Amended and Restated Bylaws (filed August 6, 2007 as Exhibit 3.3 to the Company's Quarterly Report on Form

10-Q for the quarterly period ended June 30, 2007 and incorporated herein by reference).

10.1 Registration Rights Agreement with Bear, Stearns and Co. Inc., dated March 25, 1994, as assigned to REMY Capital Partners III, L.P. (filed March 19, 2002 as Exhibit 4.3 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2001 and incorporated herein by reference).

10.2 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).*

10.3 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).*

10.4 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).*

10.5 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).*

10.6 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).*

10.7 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).*

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

10.9 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).*

10.10 Form of Executive Officer Share-Settled Performance Share Award Agreement (filed April 21, 2014 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.11 Form of Executive Officer Restricted Stock Award Agreement (filed April 21, 2014 as Exhibit 10.3 to the Company's Current Report on Form 8-K, and incorporated herein by reference).*

10.12 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).*

10.13 Form of Non-Employee Director Restricted Stock Award Agreement (filed April 21, 2014 as Exhibit 10.5 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.14 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 Letter Agreement regarding termination, effective as of January 29, 2004, entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Kenneth N. Berns and John E. Vollmer III (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).*

10.16 Employment Agreement, effective as of January 1, 2012, by and between Patterson-UTI Drilling Company LLC and James M. Holcomb (filed February 10, 2012 as Exhibit 10.17 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011 and incorporated herein by reference). *

10.17 Form of Indemnification Agreement entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Kenneth N. Berns, Curtis W. Huff, Terry H. Hunt, Charles O. Buckner, John E. Vollmer III, Seth D. Wexler, William Andrew Hendricks, Jr., Michael W. Conlon and Tiffany J. Thom (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).*

10.18 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).*

10.19 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).*

10.20 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and John E. Vollmer III (filed on February 4, 2004 as Exhibit 10.7 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*

10.21 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 for the quarterly period ended September 30, 2007 and incorporated herein by reference).*

10.22 First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and John E. Vollmer, III, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*

10.23 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 for the quarterly period ended September 30, 2007 and incorporated herein by reference).*

10.24 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of November 2, 2009, by and between Patterson-UTI Energy, Inc. and Seth D. Wexler (filed November 2, 2009 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2009 and incorporated herein by reference).*

10.25 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of April 2, 2012, by and between Patterson-UTI Energy, Inc. and William Andrew Hendricks, Jr. (filed July 30, 2012 as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012 and incorporated herein by reference).*

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

10.27 Amendment No. 1 to Credit Agreement dated as of January 9, 2015, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender and each of the other letter of credit issuer and lender parties thereto (filed January 12, 2015 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

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

10.29 Amendment No. 1 to Purchase Agreement, dated as of October 22, 2015, by and among Patterson-UTI Energy, Inc., certain subsidiaries of Patterson-UTI Energy, Inc. party thereto, and the purchasers named therein (relates to Note Purchase Agreement dated October 5, 2010) (filed October 28, 2015 as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2015 and incorporated herein by reference).

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

10.31 Amendment No. 1 to Purchase Agreement, dated as of October 22, 2015, by and among Patterson-UTI Energy, Inc., certain subsidiaries of Patterson-UTI Energy, Inc. party thereto, and the purchasers named therein (relates to Note Purchase Agreement dated June 14, 2012) (filed October 28, 2015 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2015 and incorporated herein by reference).

10.32 Reimbursement Agreement, dated as 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).

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

10.34 Term Loan Agreement, dated as March 18, 2015, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent and lender, each of the other lenders party thereto, Wells Fargo Securities, LLC, as Lead Arranger and Sole Book Runner, and Bank of America, N.A. and The Bank of Tokyo-Mitsubishi UFJ, LTD., as Co-Syndication Agents (filed March 18, 2015 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.35 Continuing Guaranty, dated as of March 18, 2015, by Patterson Petroleum LLC, Patterson-UTI Drilling Company LLC, Patterson-UTI Management Services, LLC, Universal Well Services, Inc. and Universal Pressure Pumping, Inc. (filed March 18, 2015 as Exhibit 10.2 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.+

99.1 Stipulation and Proposed Order of Dismissal, dated December 17, 2015.+

101 The following materials from Patterson-UTI Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2015, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Changes in Stockholders' Equity, (v) the Consolidated Statements of Cash Flows, and (vi) Notes to Consolidated Financial Statements.+

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