MAMMOTH
ENERGY SERVICES INC.

DIVERSIFIED ENERGY SOLUTIONS

2017
Annual Report

Mammoth Energy Services, Inc. • 2017 Annual Report

FOCUSED ON **RETURN ON INVESTED CAPITAL**

PRESSURE PUMPING | SAND | INFRASTRUCTURE

12/31/2016
$15.20/share

48% OUTPERFORMANCE VS OSX
39% OUTPERFORMANCE VS XOP

12/31/2017
$19.63/share

12/31/2016
~$570 M

MARKET CAP

UP
53%

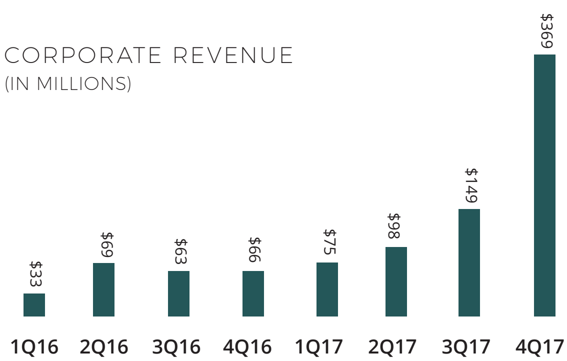
~$873 M
12/31/2017

$(92) M
2016
NET INCOME
UP ~3X
2017
$59 M

$41 M
2016
EBITDA* GENERATION
UP 4X
2017
$165 M

* See reconciliation to Adjusted EBITDA to comparable GAAP measure in the 10K, which is included later in this document.

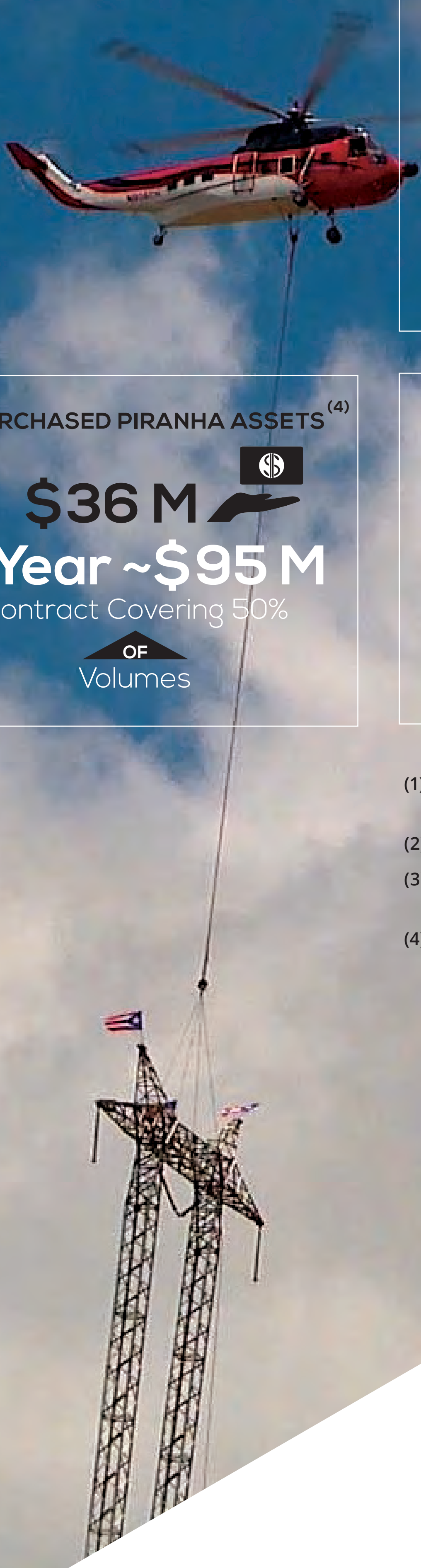
CORPORATE REVENUE
(IN MILLIONS)



SOLID FOUNDATION PROVIDES PLATFORM FOR GROWTH

In millions except per share amounts	2017	2016	2015
Total Revenue	$ 691	$ 231	$ 368
Cost of Revenue*	$ 483	$ 173	$ 275
Selling, General & Administrative	$ 50	$ 18	$ 22
Depreciation Depletion Amortization & Accretion	$ 92	$ 72	$ 74
Impairment of Long-Lived Assets	$ 4	$ 2	$ 12
Interest Expense	$ 4	$ 4	$ 5
Other, net	$ 1	$ (0)	$ 2
Bargain Purchase Gain	$ (4)	$ –	$ –
(Loss) Income Before Income Taxes	$ 62	$ (39)	$ (23)
Provision for Income Taxes	$ 3	$ 54	$ (2)
Net (loss) Income	$ 59	$ (92)	$ (22)
Share Count	41.5	31.5	30.0
Per Share	$ 1.42	$ (2.94)	$ (0.73)

* Exclusive of depreciation, depletion, amortization and accretion.



132,500 Hhp

Purchased for

~$500/Hhp

Pressure Pumping Peers Trading for

~2,000/Hhp[1]

PURCHASED PIRANHA ASSETS[4]

$36 M

3 Year ~$95 M

Contract Covering 50%

OF

Volumes

$28 M[2]

INFRASTRUCTURE INVESTMENT

$1+ B

in contracts[3]

(1) As of 4/9/2018 Peer goup includes BAS, FRAC, LBRT, PUMP, RES

(2) Includes $20 million in growth capital

(3) Includes $945 million contract with PREPA and U.S. Contracts with IOUs

(4) Assets purchased from Chieftan Sands

MAMMOTH
ENERGY SERVICES INC.

Mammoth is an integrated, growth-oriented energy service company serving (i) companies engaged in the exploration and development of North American onshore unconventional oil and natural gas reserves and (ii) government-funded utilities, private utilities, public investor-owned utilities and co operative utilities through its energy infrastructure services division. Mammoth's suite of services and products includes: pressure pumping services, infrastructure services, natural sand and proppant services, contract land and directional drilling services and other services.

MY FELLOW SHAREHOLDERS

STRONG FOUNDATION FOR GROWTH

I am very proud of what the Mammoth team achieved over the past 12 months. Mammoth entered 2017 with two frac spreads operating in the northeast, one sand processing facility (which was not operating), four rigs operating in the Permian and 20 sand hauling trucks operating in the Utica. Additionally, our other service lines, including directional drilling, coil tubing and flow back, remained challenged as utilization was low as pricing was starting to recover.

As we stand today we have six frac spreads operating in three separate basins, an infrastructure division, approximately four million tons of sand processing capacity from three separate facilities, 62 sand hauling trucks, a full rental division operating in two basins and six rigs operating in the Permian. We have also seen a significant increase in utilization and pricing in our directional drilling, coil tubing, frac stack and flow back businesses.

Commodity prices have stabilized in the $55-$65 level over the past five months, causing increased demand for the services we provide. Furthermore, we see significant demand in our infrastructure division as industry-wide spending from utilities is expected to top $60 billion per year for the next several years and could increase further if current political discussions are implemented. Our core competencies of building experienced management teams, executing at a high level, deploying capital into projects that meet our return thresholds and building a solid base on which to grow remain intact and guide the decisions we make.

The Team. The personnel in place at all levels are the most important part of any organization. It was the execution by our team of our business plan that allowed us to expand our completion services into the mid-continent, grow our sand capacity to roughly 4 Mmtpa and expand into

CEO Arty Straehla addresses Cobra team members in Yabucoa, Puerto Rico.

infrastructure services. Furthermore, our team's continued execution at the highest level has kept customer requests for our services strong across our service lines and resulted in more than $1 billion in contracts over the past 12 months in our infrastructure services division alone.

Return on Invested Capital. Anticipated return on invested capital drives capital allocation decisions at Mammoth. We seek to pursue accretive acquisitions; in fact, we looked at over 135 transactions during 2017, but we will not undertake a transaction unless it meets our targeted return threshold. If you look at the six transactions we closed in 2017, each was done at an exceptional entry point, and many of them were strategic in our effort to streamline our operations and lower costs. This discipline carried through to our organic growth initiatives as well with the purchase of additional pressure pumping equipment, the purchase and expansion of our sand mines and the expansion of our trucking fleet, with all of these investments expected to have paybacks of under three years.

Infrastructure. We always expected our infrastructure division to grow rapidly, but the build in continental U.S. backlog has exceeded our expectations. This growth is a direct result of the performance of the Cobra team which garnered the attention of investor owned utilities (IOUs) for additional work. When evaluating our investments in the infrastructure division we did not factor in potential storm recovery work. We could not envision the worst storm season in more than a decade would impact the residents of Texas, Florida and Puerto Rico. We worked closely with the utilities in all three of the affected areas and remain in Puerto Rico today performing essential repairs to the electrical infrastructure.

Core Base for Growth. Through strategic acquisitions, and well placed growth capital, Mammoth is positioned with a solid base of service lines that have the ability to grow significantly in the coming years. We will remain disciplined in our deployment of capital and grow into areas that we expect to have the best return potential.

Arty Straehla
CEO and Director
April 19, 2018

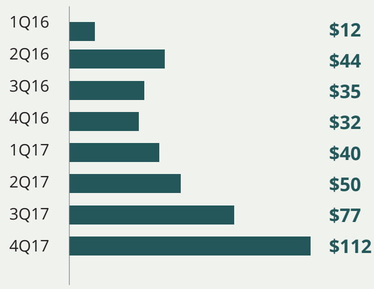
INFRASTRUCTURE SERVICES

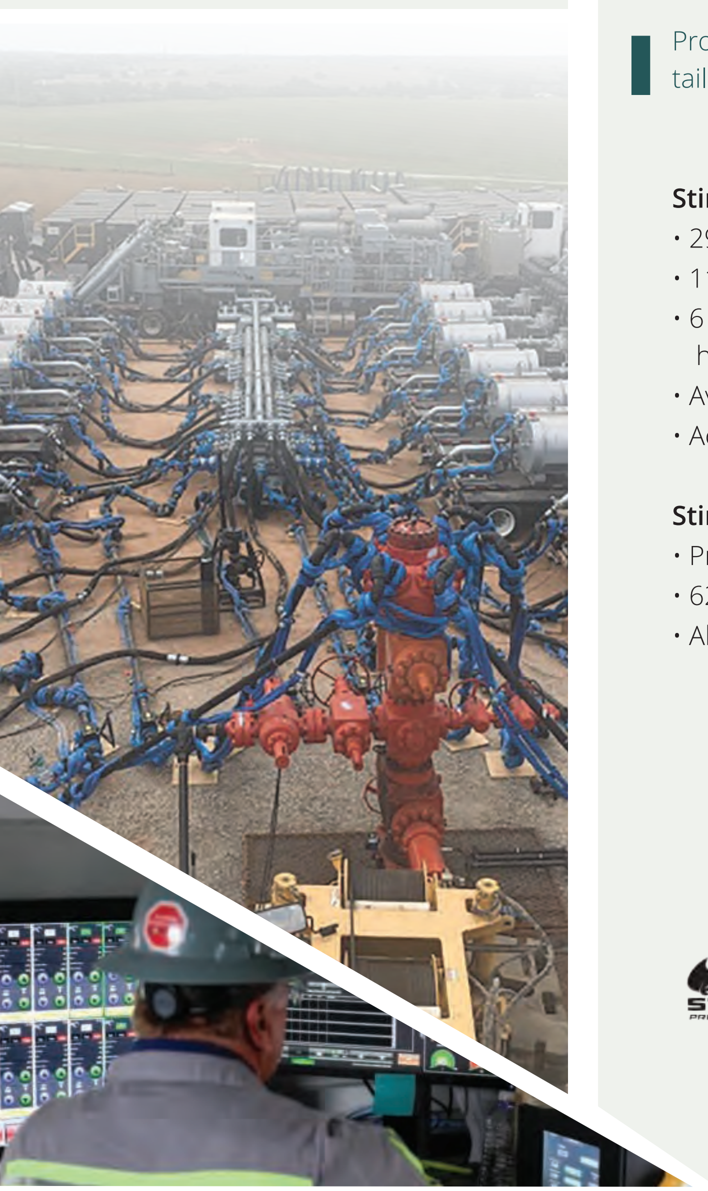
Cobra Energy is focused on all facets of the utility infrastructure industry particularly though transmission and distribution (T&D) networks and substation construction. Cobra has operations spread across the southwest, mid-west and northeast portions of the United States for multiple investor owned utilities (IOUs), government-funded utilities and cooperative utilities. In addition, crews are active in Puerto Rico. Cobra has a senior management team with an average of 25+ years of experience in the utility infrastructure industry.

- Transmission services which include bare-hand live line methods up to 345kv, hotstick up to 230kv, greenfield and brownfield substation and switchyard services.
- Overhead distribution crews are capable of working energized distribution voltages up to 34.5kv.

- Our service personnel are capable of working both overhead and underground residential distribution tickets.
- We are capable of operating in the most complicated of metro network systems and provide lead cable splicing and repair services.
- Professional services include engineering, assessments, system planning and logistical support.
- Our aviation services include the full gamut of FAA parts 133, 137 and 135.

PRESSURE PUMPING REVENUE





PRESSURE PUMPING SERVICES

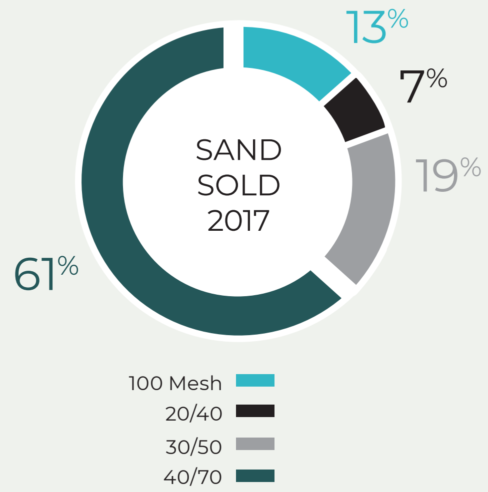
Provider of high pressure hydraulic fracturing services specifically tailored to today's unconventional resource plays

Stingray Pressure Pumping

- 291,750 hydraulic horsepower (Hhp)
- 117 fracturing units and ancillary equipment
- 6 fleets (~50,000 Hhp) specifically designed for high pressure operations
- Average age of just over 2 years as of December 31, 2017
- Active in the Utica/Marcellus, SCOOP/STACK and Permian Basins

Stingray Logistics

- Provides last-mile sand hauling solutions
- 62 tractors and pneumatic trailers
- Ability to haul multiple box systems



NATURAL SAND PROPPANT SERVICES

Provider of high quality Jordan Substrate and Wonewoc Sandstone frac sand with effective processing capacity of approximately 4.4 million tons per annum (Mtpa)[1]

Taylor Frac
- Mine and processing plant located in Taylor, Wi
- Unit train access on the Canadian National Railroad (CN)

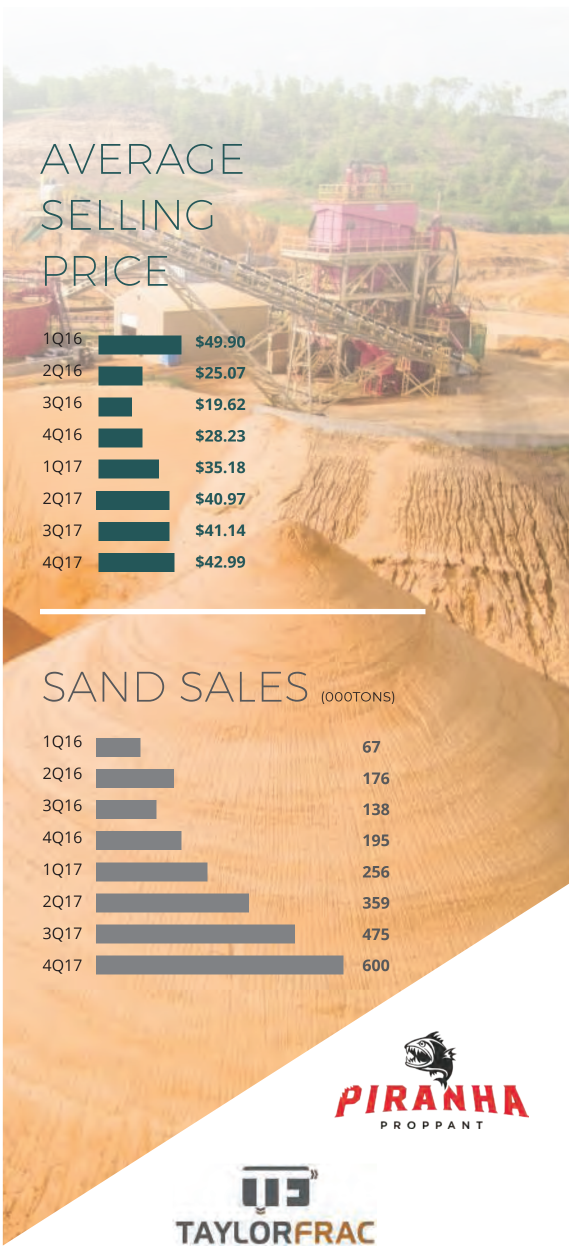
Piranha Proppant
- Mine and processing plant located in New Auburn, Wi
- Unit train access on the Union Pacific Railroad (UP)

Muskie Processing Plant
- Modern indoor sand processing plant designed for year round wet and dry operations
- Access to the Union Pacific Railroad (UP), Canadian National Railroad (CN) and Canadian Pacific Railway (CP)

(1) Includes expansion of facilities at Piranha which are expected to be completed by mid-year 2018.

The nameplate capacity of our wet and dry plants are expected to reach 8.7 Mmtpa and 5.7 Mmtpa respectively by mid-year 2018 as shown in the table below.

Plant	Wet	Dry
Taylor Frac	2,600	2,200
Piranha Proppant	4,704	2,600
Muskie Proppant	1,314	876
	8,618	**5,676**



CORPORATE INFORMATION

Board of Directors

Marc McCarthy Chairman
Arty Straehla
Paul Heerwagen
Arthur Smith
James Palm
Matthew Ross

Corporate Management

Arty Straehla – Chief Executive Officer and Director
Mark Layton – Chief Financial Officer
Phil Lancaster – VP Corporate Development
Grant DeFehr – VP Business Development
Rusty LaForge – General Counsel
Don Crist – Director of Investor Relations

Operational Management

Jim Butler – VP Operations Stingray Logistics
Keith Ellison – President Cobra Energy
Baron Honea – President Bison Drilling
Dennis Hines – President Natural Sand Proppant Services
Bernie Lancaster – VP Operations Redback Energy Services
Joe Dale Price – President Bison Trucking
Mike Rexroad – President Stingray Pressure Pumping and Cementing Services
Wayne Sluice – President Sand Tiger Lodge
Jack Tarver – VP Operations Stingray Energy Services
Danny Ward – President Panther Drilling

Corporate Headquarters

Mammoth Energy Services, Inc.
14201 Caliber Drive
Suite 300
Oklahoma City, Oklahoma 73134
Phone (405) 608-6007
Mammoth is traded on the Nasdaq Global Select Market under the stock symbol TUSK.

Annual Meeting

Annual meeting to be held at 2 pm CDT on June 7, 2018 at 3117 NW 137th Street, Oklahoma City, OK-73134

Transfer Agent

Computershare Trust Company, NA.

Auditors

Grant Thornton, LLP
211 N Robinson Ave.
Oklahoma City, OK 73102

Investor Inquiries

Investor Contact
Don Crist – Director Investor Relations
(405) 608-6048
dcrist@mammothenergy.com

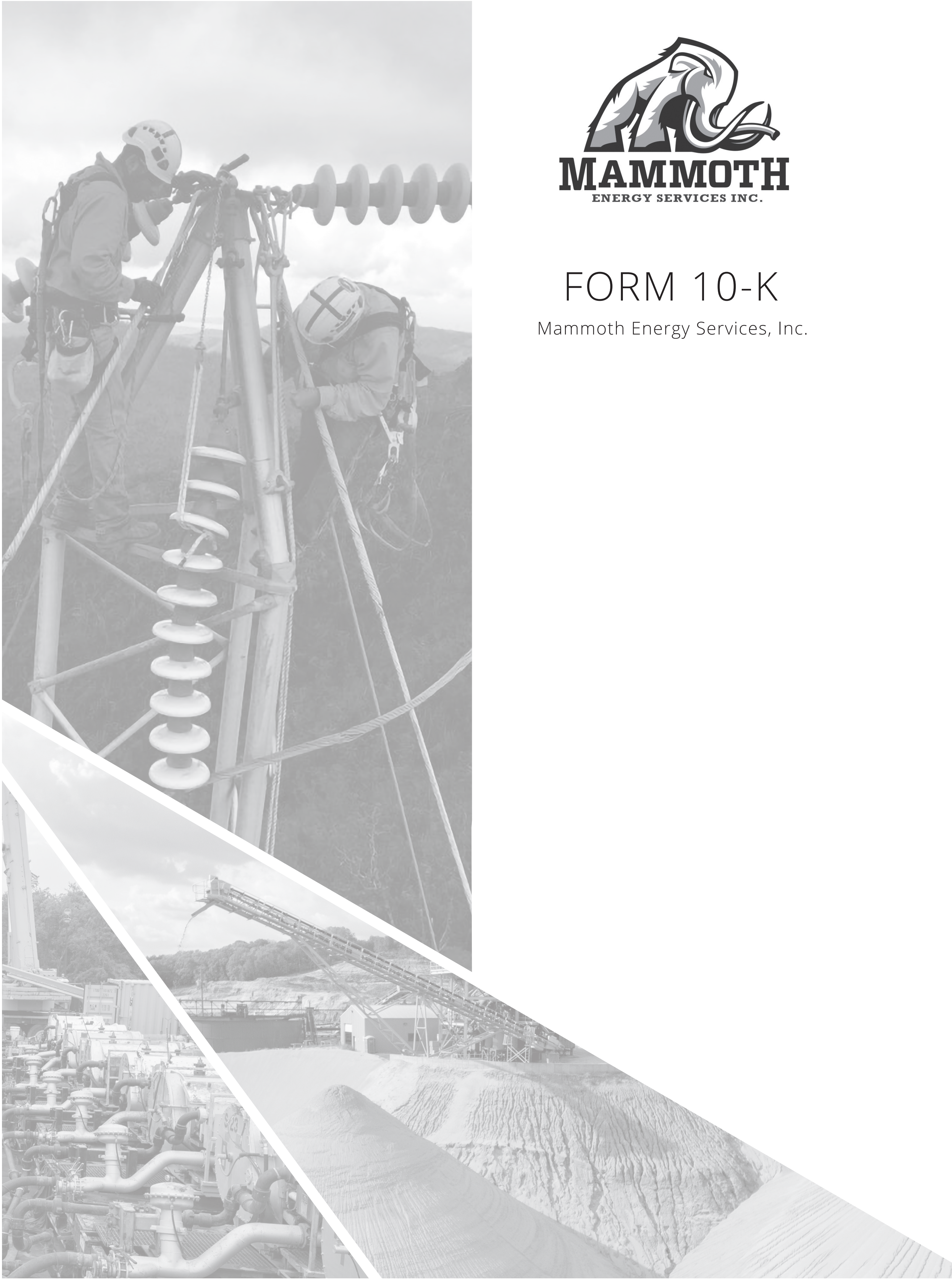
The Form 10-K, as filed with the Securities and Exchange Commission (SEC), may be obtained at no cost to any shareholder upon written request to Mammoth Energy Services, Inc., Attention Investor Relations.

Forward-Looking Statements and Cautionary Statements

This letter (and any oral statements made regarding the subjects of this letter) contains certain statements and information that include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts that address activities, events or developments that Mammoth expects, believes or anticipates will or may occur in the future are forward-looking statements. The words "anticipate," "believe," "ensure," "expect," "if," "intend," "plan," "estimate," "project," "forecasts," "predict," "outlook," "aim," "will," "could," "should," "potential," "would," "may," "probable," "likely" and similar expressions, and the negative thereof, are intended to identify forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this news release may include statements, estimates and projections regarding Mammoth's business outlook and plans, future financial position, liquidity and capital resources, operations, performance, including under Cobra utility infrastructure restoration contract in Puerto Rico, acquisitions, returns, capital expenditure budgets, costs and other guidance regarding future developments. Forward-looking statements are not assurances of future performance. These forward-looking statements are based on management's current expectations and beliefs, forecasts for Mammoth's existing operations, experience and perception of historical trends, current conditions, anticipated future developments and their effect on Mammoth, and other factors believed to be appropriate. Although management believes that the expectations and assumptions reflected in these forward-looking statements are reasonable as and when made, no assurance can be given that these assumptions are accurate or that any of these expectations will be achieved (in full or at all). Moreover, these forward-looking statements are subject to significant risks and uncertainties, including those described in Mammoth's Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other filings Mammoth makes with the Securities and Exchange Commission, which may cause actual results to differ materially from its historical experience and present expectations or projections which are implied or expressed by the forward-looking statements. Important factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to: the failure to receive or delays in receiving governmental authorizations, approvals and/or payments; risks relating to economic conditions; delays in or failure of delivery of current or future orders of specialized equipment; the loss of or interruption in operations of one or more key suppliers or customers; the effects of government regulation, permitting and other legal requirements; operating risks; the adequacy of our capital resources and liquidity; weather; natural disasters; litigation; competition in the oil and natural gas and infrastructure industries; and costs and availability of resources.

Readers are cautioned not to place undue reliance on any forward-looking statement which speaks only as of the date on which such statement is made. Mammoth undertakes no obligation to correct, revise or update any forward-looking statement after the date such statement is made, whether as a result of new information, future events or otherwise, except as required by applicable law.

MAMMOTH
ENERGY SERVICES INC.



FORM 10-K

Mammoth Energy Services, Inc.

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

Form 10-K

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2017

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

Commission File No. 001-37917

Mammoth Energy Services, Inc.

(Exact name of registrant as specified in its charter)

Delaware		**32-0498321**
(State or other jurisdiction of incorporation or organization)		(I.R.S. Employer Identification No.)
14201 Caliber Drive, Suite 300 Oklahoma City, Oklahoma	**(405) 608-6007**	**73134**
(Address of principal executive offices)	(Registrant's telephone number, including area code)	(Zip Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	The Nasdaq Stock Market LLC

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) 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. Yes ☐ No ☒

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

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

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

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

The aggregate market value of common equity held by non-affiliates of the registrant as of June 30, 2017 was approximately $154.5 million, calculated based on the closing price of the common stock on the Nasdaq Global Select Market on that date.

As of February 20, 2018, there were 44,589,306 shares of our $0.01 par value common stock outstanding.

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GLOSSARY OF OIL AND NATURAL GAS AND ELECTRICAL INFRASTRUCTURE TERMS

The following is a glossary of certain oil and natural gas and natural sand proppant industry terms used in this report:

Blowout	An uncontrolled flow of reservoir fluids into the wellbore, and sometimes catastrophically to the surface. A blowout may consist of salt water, oil, natural gas or a mixture of these. Blowouts can occur in all types of exploration and production operations, not just during drilling operations. If reservoir fluids flow into another formation and do not flow to the surface, the result is called an underground blowout. If the well experiencing a blowout has significant open-hole intervals, it is possible that the well will bridge over (or seal itself with rock fragments from collapsing formations) down-hole and intervention efforts will be averted.
Bottomhole assembly	The lower portion of the drillstring, consisting of (from the bottom up in a vertical well) the bit, bit sub, a mud motor (in certain cases), stabilizers, drill collar, heavy-weight drillpipe, jarring devices ("jars") and crossovers for various threadforms. The bottomhole assembly must provide force for the bit to break the rock (weight on bit), survive a hostile mechanical environment and provide the driller with directional control of the well. Oftentimes the assembly includes a mud motor, directional drilling and measuring equipment, measurements-while-drilling tools, logging-while-drilling tools and other specialized devices.
Cementing	To prepare and pump cement into place in a wellbore.
Coiled tubing	A long, continuous length of pipe wound on a spool. The pipe is straightened prior to pushing into a wellbore and rewound to coil the pipe back onto the transport and storage spool. Depending on the pipe diameter (1 in. to 4 1/2 in.) and the spool size, coiled tubing can range from 2,000 ft. to 23,000 ft. (610 m to 6,096 m) or greater length.
Completion	A generic term used to describe the assembly of down-hole tubulars and equipment required to enable safe and efficient production from an oil or gas well. The point at which the completion process begins may depend on the type and design of the well.
Directional drilling	The intentional deviation of a wellbore from the path it would naturally take. This is accomplished through the use of whipstocks, bottomhole assembly (BHA) configurations, instruments to measure the path of the wellbore in three-dimensional space, data links to communicate measurements taken down-hole to the surface, mud motors and special BHA components and drill bits, including rotary steerable systems, and drill bits. The directional driller also exploits drilling parameters such as weight on bit and rotary speed to deflect the bit away from the axis of the existing wellbore. In some cases, such as drilling steeply dipping formations or unpredictable deviation in conventional drilling operations, directional-drilling techniques may be employed to ensure that the hole is drilled vertically. While many techniques can accomplish this, the general concept is simple: point the bit in the direction that one wants to drill. The most common way is through the use of a bend near the bit in a down-hole steerable mud motor. The bend points the bit in a direction different from the axis of the wellbore when the entire drillstring is not rotating. By pumping mud through the mud motor, the bit turns while the drillstring does not rotate, allowing the bit to drill in the direction it points. When a particular wellbore direction is achieved, that direction may be maintained by rotating the entire drillstring (including the bent section) so that the bit does not drill in a single direction off the wellbore axis, but instead sweeps around and its net direction coincides with the existing wellbore. Rotary steerable tools allow steering while rotating, usually with higher rates of penetration and ultimately smoother boreholes.
Down-hole	Pertaining to or in the wellbore (as opposed to being on the surface).
Down-hole motor	A drilling motor located in the drill string above the drilling bit powered by the flow of drilling mud. Down-hole motors are used to increase the speed and efficiency of the drill bit or can be used to steer the bit in directional drilling operations. Drilling motors have become very popular because of horizontal and directional drilling applications and the day rates for drilling rigs.
Drilling rig	The machine used to drill a wellbore.
Drillpipe or Drill pipe	Tubular steel conduit fitted with special threaded ends called tool joints. The drillpipe connects the rig surface equipment with the bottomhole assembly and the bit, both to pump drilling fluid to the bit and to be able to raise, lower and rotate the bottomhole assembly and bit.
Drillstring or Drill string	The combination of the drillpipe, the bottomhole assembly and any other tools used to make the drill bit turn at the bottom of the wellbore.
Horizontal drilling	A subset of the more general term "directional drilling," used where the departure of the wellbore from vertical exceeds about 80 degrees. Note that some horizontal wells are designed such that after reaching true 90-degree horizontal, the wellbore may actually start drilling upward. In such cases, the angle past 90 degrees is continued, as in 95 degrees, rather than reporting it as deviation from vertical, which would then be 85 degrees. Because a horizontal well typically penetrates a greater length of the reservoir, it can offer significant production improvement over a vertical well.
Hydraulic fracturing	A stimulation treatment routinely performed on oil and gas wells in low permeability reservoirs. Specially engineered fluids are pumped at high pressure and rate into the reservoir interval to be treated, causing a vertical fracture to open. The wings of the fracture extend away from the wellbore in opposing directions according to the natural stresses within the formation. Proppant, such as grains of sand of a particular size, is mixed with the treatment fluid to keep the fracture open when the treatment is complete. Hydraulic fracturing creates high-conductivity communication with a large area of formation and bypasses any damage that may exist in the near-wellbore area.
Hydrocarbon	A naturally occurring organic compound comprising hydrogen and carbon. Hydrocarbons can be as simple as methane, but many are highly complex molecules, and can occur as gases, liquids or solids. Petroleum is a complex mixture of hydrocarbons. The most common hydrocarbons are natural gas, oil and coal.
Mesh size	The size of the proppant that is determined by sieving the proppant through screens with uniform openings corresponding to the desired size of the proppant. Each type of proppant comes in various sizes, categorized as mesh sizes, and the various mesh sizes are used in different applications in the oil and natural gas industry. The mesh number system is a measure of the number of equally sized openings per square inch of screen through which the proppant is sieved.

Mud motors	A positive displacement drilling motor that uses hydraulic horsepower of the drilling fluid to drive the drill bit. Mud motors are used extensively in directional drilling operations.
Natural gas liquids	Components of natural gas that are liquid at surface in field facilities or in gas processing plants. Natural gas liquids can be classified according to their vapor pressures as low (condensate), intermediate (natural gasoline) and high (liquefied petroleum gas) vapor pressure.
Nitrogen pumping unit	A high-pressure pump or compressor unit capable of delivering high-purity nitrogen gas for use in oil or gas wells. Two basic types of units are commonly available: a nitrogen converter unit that pumps liquid nitrogen at high pressure through a heat exchanger or converter to deliver high-pressure gas at ambient temperature, and a nitrogen generator unit that compresses and separates air to provide a supply of high pressure nitrogen gas.
Plugging	The process of permanently closing oil and gas wells no longer capable of producing in economic quantities. Plugging work can be performed with a well servicing rig along with wireline and cementing equipment; however, this service is typically provided by companies that specialize in plugging work.
Plug	A down-hole packer assembly used in a well to seal off or isolate a particular formation for testing, acidizing, cementing, etc.; also a type of plug used to seal off a well temporarily while the wellhead is removed.
Pounds per square inch	A unit of pressure. It is the pressure resulting from a one pound force applied to an area of one square inch.
Pressure pumping	Services that include the pumping of liquids under pressure.
Producing formation	An underground rock formation from which oil, natural gas or water is produced. Any porous rock will contain fluids of some sort, and all rocks at considerable distance below the Earth's surface will initially be under pressure, often related to the hydrostatic column of ground waters above the reservoir. To produce, rocks must also have permeability, or the capacity to permit fluids to flow through them.
Proppant	Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.
Resource play	Accumulation of hydrocarbons known to exist over a large area.
Shale	A fine-grained, fissile, sedimentary rock formed by consolidation of clay- and silt-sized particles into thin, relatively impermeable layers.
Tight oil	Conventional oil that is found within reservoirs with very low permeability. The oil contained within these reservoir rocks typically will not flow to the wellbore at economic rates without assistance from technologically advanced drilling and completion processes. Commonly, horizontal drilling coupled with multistage fracturing is used to access these difficult to produce reservoirs.
Tight sands	A type of unconventional tight reservoir. Tight reservoirs are those which have low permeability, often quantified as less than 0.1 millidarcies.
Tubulars	A generic term pertaining to any type of oilfield pipe, such as drill pipe, drill collars, pup joints, casing, production tubing and pipeline.
Unconventional resource	An umbrella term for oil and natural gas that is produced by means that do not meet the criteria for conventional production. What has qualified as "unconventional" at any particular time is a complex function of resource characteristics, the available exploration and production technologies, the economic environment, and the scale, frequency and duration of production from the resource. Perceptions of these factors inevitably change over time and often differ among users of the term. At present, the term is used in reference to oil and gas resources whose porosity, permeability, fluid trapping mechanism, or other characteristics differ from conventional sandstone and carbonate reservoirs. Coalbed methane, gas hydrates, shale gas, fractured reservoirs and tight gas sands are considered unconventional resources.
Wellbore	The physical conduit from surface into the hydrocarbon reservoir.
Well stimulation	A treatment performed to restore or enhance the productivity of a well. Stimulation treatments fall into two main groups, hydraulic fracturing treatments and matrix treatments. Fracturing treatments are performed above the fracture pressure of the reservoir formation and create a highly conductive flow path between the reservoir and the wellbore. Matrix treatments are performed below the reservoir fracture pressure and generally are designed to restore the natural permeability of the reservoir following damage to the near wellbore area. Stimulation in shale gas reservoirs typically takes the form of hydraulic fracturing treatments.
Wireline	A general term used to describe well-intervention operations conducted using single-strand or multi-strand wire or cable for intervention in oil or gas wells. Although applied inconsistently, the term commonly is used in association with electric logging and cables incorporating electrical conductors.
Workover	The process of performing major maintenance or remedial treatments on an oil or gas well. In many cases, workover implies the removal and replacement of the production tubing string after the well has been killed and a workover rig has been placed on location. Through-tubing workover operations, using coiled tubing, snubbing or slickline equipment, are routinely conducted to complete treatments or well service activities that avoid a full workover where the tubing is removed. This operation saves considerable time and expense.

The following is a glossary of certain electrical infrastructure industry terms used in this report:

Distribution	The distribution of electricity from the transmission system to individual customers.
Substation	A part of an electrical transmission and distribution system that transforms voltage from high to low, or the reverse.
Transmission	The movement of electrical energy from a generating site, such as a power plant, to an electric substation.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this Annual Report on Form 10-K (this "annual report" or "report") that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act and the Private Securities Litigation Reform Act of 1995.

Forward-looking statements may include statements about our:

- business strategy;
- pending or future acquisitions and future capital expenditures;
- ability to obtain permits and governmental approvals;
- technology;
- financial strategy;
- future operating results; and
- plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this annual report, are forward-looking statements. These forward-looking statements may be found in the “Business,” “Risk Factors,” “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” and other sections of this annual report. In some cases, you can identify forward-looking statements by terminology such as “may,” “will,” “could,” “should,” “would,” “expect,” “plan,” “project,” “budget,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target,” “seek,” “objective,” “continue,” “will be,” “will benefit,” or “will continue,” the negative of such terms or other comparable terminology.

The forward-looking statements contained in this annual report are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors, which are difficult to predict and many of which are beyond our control. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, our management’s assumptions about future events may prove to be inaccurate. Our management cautions all readers that the forward-looking statements contained in this annual report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the many factors including those described in Item 1A. “Risk Factors” and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this annual report. All forward-looking statements speak only as of the date of this annual report. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

PART I.

The historical financial information for periods prior to October 12, 2016, contained in this annual report relates to Mammoth Energy Partners LP, a Delaware limited partnership, or the Partnership. On October 12, 2016, the Partnership was converted into a Delaware limited liability company named Mammoth Energy Partners LLC, or Mammoth LLC, and then each member of Mammoth LLC contributed all of its membership interests in Mammoth LLC to Mammoth Energy Services, Inc., a Delaware corporation, or Mammoth Inc. Prior to the conversion and the contribution, Mammoth Inc. was a wholly-owned subsidiary of the Partnership. Following the conversion and the contribution, Mammoth LLC (as the converted successor to the Partnership) became a wholly-owned subsidiary of Mammoth Inc.

On October 13, 2016, Mammoth Inc. priced 7,750,000 shares of its common stock in its initial public offering, or the IPO, at a price to the public of $15.00 per share and, on October 14, 2016, Mammoth Inc.'s common stock began trading on The Nasdaq Global Select Market under the symbol "TUSK." On October 19, 2016, Mammoth Inc. closed its IPO. Unless the context otherwise requires, references in this report to "we," "our," "us" or like terms, when used in a historical context for periods prior to October 12, 2016 refer to the Partnership and its subsidiaries. References in this report to "we," "our," "us" or like terms, when used for periods beginning on or after October 12, 2016 refer to Mammoth Inc. and its subsidiaries.

Item 1. Business

Overview

We are an integrated, growth-oriented energy service company serving companies engaged in the exploration and development of North American onshore unconventional oil and natural gas reserves and government-funded utilities, private utilities, public investor owned utilities, or IOUs, and co-operative utilities, or Co-Ops, through our energy infrastructure business. Our primary business objective is to grow our operations and create value for our stockholders through organic opportunities and accretive acquisitions. Our suite of services includes pressure pumping services, infrastructure services, natural sand proppant services, contract land and directional drilling services and other energy services. Our pressure pumping services division provides hydraulic fracturing services. Our infrastructure services division provides construction, upgrade, maintenance and repair services to the electrical infrastructure industry. Our natural sand proppant services division mines, processes and sells proppant for hydraulic fracturing. Our contract land and directional drilling services division provides drilling rigs and crews for operators as well as rental equipment, such as mud motors and operational tools, for both vertical and horizontal drilling. In addition to these service divisions, we also provide coil tubing services, pressure control services, flowback services, cementing services, equipment rentals and remote accommodations. We believe that the services we offer play a critical role in increasing the ultimate recovery and present value of production streams from unconventional resources as well as maintaining and improving electrical infrastructure. Our complementary suite of energy services provides us with the opportunity to cross-sell our services and expand our customer base and geographic positioning.

"Unconventional resources" references the different manner by which they are exploited as compared to the extraction of conventional resources. In unconventional drilling, the wellbore is generally drilled to specific objectives within narrow parameters, often across long, lateral intervals within narrow horizontal formations offering greater contact area with the producing formation. Typically, the well is then hydraulically fractured at multiple stages to optimize production.

Our facilities and service centers are strategically located in Ohio, Texas, Oklahoma, Wisconsin, Minnesota, West Virginia, Kentucky, Puerto Rico and Alberta, Canada primarily to serve the following areas:

- The Utica Shale in Eastern Ohio;
- Southern Ohio;
- The Permian Basin in West Texas;
- The Appalachian Basin in the Northeast;
- The SCOOP and STACK in Oklahoma;
- The Arkoma Basin in Arkansas and Oklahoma;
- The Anadarko Basin in Oklahoma;
- The Marcellus Shale in West Virginia and Pennsylvania;
- Southeastern New Mexico;
- The Barnett Shale in Texas;
- The Granite Wash and Mississippi Shale in Oklahoma and Texas;
- The Cana Woodford and Woodford Shales and the Cleveland Sand in Oklahoma;
- The Eagle Ford Shale in Texas;

- Puerto Rico; and
- The oil sands in Alberta, Canada.

Our operational division heads have an extensive track record in the oilfield and infrastructure service businesses with an average of over 35 years of oilfield services experience and over 25 years of infrastructure services experience. They bring valuable regional expertise and long-term customer relationships to our business. We provide our completion and production and contract land and directional drilling services to a diversified range of both public and private independent oil and natural gas producers and our infrastructure services to government-funded utilities, private utilities, public IOUs and Co-Ops. Our top five customers for the year ended December 31, 2017, representing 71% of our revenue, were Gulfport Energy Corporation, or Gulfport, the Puerto Rico Electric Power Authority, or PREPA, Newfield Exploration Company, or Newfield, Rice Energy, Inc., or Rice Energy, and Surge Operating LLC, or Surge Operating. For the year ended December 31, 2016, our top five customers, representing 80% of our revenue, were Gulfport, Japan Canada Oil Sands Limited, or Oil Sands Limited, Rice Energy, Surge Operating and Hilcorp Energy Corporation. For the year ended December 31, 2015, our top five customers, representing 71% of our revenue, were Gulfport, EQT Production Company, Oil Sands Limited, RSP Permian LLC and Bantrel Co.

Our Services

Our revenues, operating profits and identifiable assets are primarily attributable to four reportable segments: pressure pumping services, infrastructure services, natural sand proppant services and contract land and directional drilling services. For the year ended December 31, 2016, we identified five reportable segments consisting of pressure pumping services, well services, natural sand proppant services, contract land and directional drilling services and other energy services. We changed our reportable segment presentation in 2017, as we no longer consider well services, which included Redback Energy Services LLC, Redback Coil Tubing LLC and Mammoth Energy Partners LLC, and our other energy services, which included Great White Sand Tiger Lodging Ltd., to be significant to the understanding of our results. We now present the results of our well service and other energy service activities as "Other." Additionally, during 2017, we added a new reportable segment for our infrastructure services activities. For additional information, see Note 17 to our consolidated financial statements included elsewhere in this annual report.

Pressure Pumping Services

Pressure Pumping. We provide pressure pumping services, also known as hydraulic fracturing, to exploration and production companies. These services are intended to optimize hydrocarbon flow paths during the completion phase of horizontal shale wellbores. Currently, we provide pressure pumping services in the Utica Shale of Eastern Ohio, the mid-continent region in Oklahoma and the Permian Basin in Texas. Three of our fleets are currently providing services in the Utica Shale. Two of these fleets operate under a four-year contract expiring in September 2018. Additionally, we have two fleets operating in the mid-continent region and one fleet operating in the Permian Basin. Our pressure pumping services include the following:

- ***Hydraulic Fracturing.*** We provide high-pressure hydraulic fracturing services. Fracturing services are performed to enhance the production of oil and natural gas from formations having low permeability such that the flow of hydrocarbons is restricted. We have significant expertise in multistage fracturing of horizontal oil and natural gas producing wells in shale and other unconventional geological formations.

  The fracturing process consists of pumping a fracturing fluid into a well at sufficient pressure to fracture the formation. Materials known as proppants, in our case primarily sand or ceramic beads, are suspended in the fracturing fluid and are pumped into the fracture to prop it open. The fracturing fluid is designed to “break,” or loosen viscosity, and be forced out of the formation by its pressure, leaving the proppants suspended in the fractures created, thereby increasing the mobility of the hydrocarbons. As a result of the fracturing process, production rates are usually enhanced substantially, thus increasing the rate of return for the operator.

  We own and operate fleets of mobile hydraulic fracturing units and other auxiliary heavy equipment to perform fracturing services. Our hydraulic fracturing units consist primarily of a high pressure hydraulic pump, a diesel engine, a transmission and various hoses, valves, tanks and other supporting equipment that are typically mounted to a flat-bed trailer. As of December 31, 2017, we had grown our pressure pumping business to six high pressure fleets consisting of an aggregate 117 high pressure fracturing units with pump nameplate capacity of 291,750 horsepower.

  We refer to the group of fracturing units, other equipment and vehicles necessary to perform a typical fracturing job as a “fleet” and the personnel assigned to each fleet as a “crew.” We operate on a 24-hour-per-day basis and we typically staff three crews per fleet. All of our fracturing units and high pressure pumps are manufactured to our specifications to enhance the performance and durability of our equipment and meet our customers' needs.

Each hydraulic fracturing fleet includes a mobile, on-site control center that monitors pressures, rates and volumes, as applicable. From there, our field-level managers supervise the job-site by radio. Each control center is equipped with high bandwidth satellite hardware that provides continuous upload and download of job telemetry data. The data is delivered on a real-time basis to on-site job personnel, the operator and personnel at our headquarters for display in both digital and graphical form.

An important element of fracturing services is determining the proper fracturing fluid, proppants and injection program to maximize results. In virtually all of our hydraulic fracturing jobs, our customers specify the composition of the fracturing fluid to be used. The fracturing fluid may contain hazardous substances, such as hydrochloric acid and certain petrochemicals. Our customers are responsible for the disposal of the fracturing fluid that flows back out of the well as waste water. The customers remove the water from the well using a controlled flow-back process, and we are generally not involved in that process or in the disposal of the fluid.

Master Services Agreements. We contract with most of our pressure pumping customers under master service agreements, or MSAs. Generally, our MSAs, including those relating to our hydraulic fracturing services, specify payment terms, audit rights and insurance requirements and allocate certain operational risks through indemnity and similar provision.

Infrastructure Services

Our infrastructure services business provides restoration, repair, transmission and distribution, or T&D, and commercial services. We offer a broad range of services on electric transmission and distribution networks and substation facilities, which include construction, upgrade, maintenance and repair services. Our T&D services include the construction, upgrade, maintenance and repair of high voltage transmission lines, substations and lower voltage overhead and underground distribution systems. We also provide storm repair and restoration services in response to storms and other disasters, including hurricanes Harvey, Irma and Maria. In addition, we provide infrastructure services in the northeast, southwest and midwest portions of the United States. Our commercial services include the installation, maintenance and repair of commercial wiring.

We currently have agreements in place with government-funded utilities, private utilities, public IOUs and Co-Ops. In particular, on October 19, 2017, one of our subsidiaries, Cobra Acquisitions LLC, or Cobra, entered into an emergency master services agreement with PREPA (such agreement, as subsequently amended through December 21, 2017, is hereinafter referred to as the initial PREPA contract). The initial PREPA contract has a one-year term and provided for up to $200.0 million of services which was initially expected to be fully utilized within a 120-day period. The scope of the work provided for in the initial PREPA contract included labor, supervision, tools and equipment to perform storm repairs at various locations in Puerto Rico. The initial PREPA contract was fully applied to services performed by Cobra as of January 3, 2018. Due to the continuing need for Cobra's services, on January 28, 2018, Cobra and PREPA amended the initial PREPA contract to increase the total contract amount by an additional $245.4 million up to a total of $445.4 million. Under the terms of this amendment, the number of workers requested by PREPA and provided by Cobra increased to at least 882, up from 434 in the initial PREPA contract, and the billable daily rate for those workers was decreased. On February 27, 2017, Cobra and PREPA again amended the PREPA contract to further increase the contract amount by $500.0 million up to a total of $945.4 million. In addition to continuing its repair and restoration work, under the terms of this amendment Cobra will be able to source construction materials needed to rebuild the electrical infrastructure in Puerto Rico on a pass-through basis. To support its efforts, Cobra has two berthing barges with accommodations for approximately 550 people mobilized to Puerto Rico. In addition to its employees, Cobra also subcontracts additional resources where needed to assist in its repair efforts, including helicopters and pilots to erect towers and pull wire for reconnection, steel workers to fix transmission poles and rework steel damaged in the storm, road equipment and operators to carve access to work sites, tree services to clear brush and trees and security teams. Based on the current level of services provided, Cobra anticipates the additional amounts specified in the amendments will fund its activities in Puerto Rico through mid-2018.

Natural Sand Proppant Services

In our natural sand proppant business, we mine, process and sell sand. We also buy processed sand from suppliers on the spot market and resell that sand. Natural sand proppant, also known as frac sand, is the most widely used type of proppant due to its broad applicability in unconventional oil and natural gas wells and its cost advantage relative to other proppants. Natural frac sand may be used as proppant in all but the highest pressure and temperature environments and is being employed in nearly all major U.S. unconventional oil and natural gas producing basins, including those in which we operate.

At our Barron County and Jackson County, Wisconsin plants, we mine and process sand into premium monocrystalline sand (also known as frac sand), a specialized mineral that is used as a proppant. We also purchase raw or washed sand and process it at our indoor sand processing plant located in Pierce County, Wisconsin. We sell sand to our customers for use in their hydraulic fracturing operations to enhance recovery rates from unconventional wells. Our sand processing plants produce a range of frac sand sizes for use in all major North American shale basins, including a majority of the standard proppant sizes as defined by the ISO/API 13503-2 specifications. These grain sizes can be customized to meet the demands of our customers with respect to a specific well. Our supply of Jordan substrate exhibits the physical properties necessary to withstand the completion and production environments of the wells in these shale basins. Our indoor processing plant in Pierce County, Wisconsin is designed for year-round continuous wet and dry plant operation. Our processing plants in Barron County and Jackson County, Wisconsin have indoor dry plants designed to operate year-round and outdoor wet plants that generally operate eight months per year.

We also provide logistics solutions to facilitate delivery of our frac sand products to our customers. Our frac sand products are primarily shipped by rail to our customers in the Utica Shale, SCOOP/STACK, DJ Basin, Permian Basin and the Montney Shale in British Columbia and Alberta, Canada. Our logistics capabilities in this regard are important to our customers, who focus on both the reliability and flexibility of product delivery. Because our customers generally find it impractical to store frac sand in large quantities near their job sites, they typically prefer product to be delivered where and as needed, which requires predictable and efficient loading and shipping capabilities. We contract with third party providers to transport our frac sand products to railroad facilities for delivery to our customers. We currently lease or have access to origin transloading facilities on the Canadian National Railway Company (CN), Union Pacific (UP), Burlington Northern Santa Fe (BNSF) and the Canadian Pacific (CP) rail systems and use an in-house railcar fleet that we lease from various third parties to deliver our frac sand products to our customers. Origin transloading facilities on multiple railways allow us to provide predictable and efficient loading and shipping of our frac sand products. We also utilize a destination transloading facility in Yorkville, Ohio, to serve the Utica Shale, and utilize destination transloading facilities located in other North American resource plays, including the Montney Shale, to meet our customers' delivery needs.

Contract Land and Directional Drilling Services

Our contract land and directional drilling business provides contract drilling and directional drilling services.

Contract Drilling. As part of our contract drilling services, we provide both vertical and horizontal drilling services to our customers. Currently, we perform our contract drilling services in the Permian Basin of West Texas.

A majority of the wells we drill for our customers are drilled in unconventional basins or resource plays. These plays are generally characterized by complex geologic formations that often require higher horsepower, premium rigs and experienced crews to reach targeted depths. As of December 31, 2017, we owned 12 land drilling rigs, ranging from 800 to 1,500 horsepower, eight of which are specifically designed for drilling horizontal and directional wells, which continue to increase as a percentage of total wells drilled in North America and are frequently utilized in unconventional resource plays. As of December 31, 2017, three of our 12 drilling rigs were operating under term contracts with a term of more than one well or a stated period of time. To facilitate the provision of our contract drilling services, as of December 31, 2017, we also owned 42 trucks specifically tailored to move rigs and four cranes to assist us in moving rigs in the Permian Basin.

A land drilling rig generally consists of engines, a hoisting system, a rotating system, a drawworks, a mast, pumps and related equipment to circulate the drilling fluid under various pressures, blowout preventers, drill string and related equipment. The engines power the different pieces of equipment, including a rotary table or top drive that turns the drill pipe, or drill string, causing the drill bit to bore through the subsurface rock layers. Drilling rigs use long strings of drill pipe and drill collars to drill wells. Drilling rigs are also used to set heavy strings of large-diameter pipe, or casing, inside the borehole. Because the total weight of the drill string and the casing can exceed 500,000 pounds, drilling rigs require significant hoisting and braking capacities. Generally, a drilling rig's hoisting system is made up of a mast, or derrick, a drilling line, a traveling block and hook assembly and ancillary equipment that attaches to the rotating system, a mechanism known as the drawworks. The drawworks mechanism consists of a revolving drum, around which the drilling line is wound, and a series of shafts, clutches and chain and gear drives for generating speed changes and reverse motion. The drawworks also houses the main brake, which has the capacity to stop and sustain the weights used in the drilling process. When heavy loads are being lowered, a hydromatic or electric auxiliary brake assists the main brake to absorb the great amount of energy developed by the mass of the traveling block, hook assembly, drill pipe, drill collars and drill bit or casing being lowered into the well.

The rotating equipment from top to bottom consists of a swivel, the kelly bushing, the kelly, the rotary table, drill pipe, drill collars and the drill bit. We refer to the equipment between the swivel and the drill bit as the drill stem. The swivel assembly sustains the weight of the drill stem, permits its rotation and affords a rotating pressure seal and passageway for circulating drilling fluid into the top of the drill string. The swivel also has a large handle that fits inside the hook assembly at the bottom of the traveling block. Drilling fluid enters the drill stem through a hose, called the rotary hose, attached to the side of the swivel. The kelly is a triangular, square or hexagonal piece of pipe, usually 40 feet long, that transmits torque from the rotary table to the drill stem and permits its vertical movement as it is lowered into the hole. The bottom end of the kelly fits inside a corresponding triangular, square or hexagonal opening in a device called the kelly bushing. The kelly bushing, in turn, fits into a part of the rotary table called the master bushing. As the master bushing rotates, the kelly bushing also rotates, turning the kelly, which rotates the drill pipe and thus the drill bit. Drilling fluid is pumped through the kelly on its way to the bottom. The rotary table, equipped with its master bushing and kelly bushing, supplies the necessary torque to turn the drill stem. The drill pipe and drill collars are both steel tubes through which drilling fluid can be pumped. Drill pipe comes in 30-foot sections, or joints, with threaded sections on each end. Drill collars are heavier than drill pipe and are also threaded on the ends. Collars are used on the bottom of the drill stem to apply weight to the drill bit. At the end of the drill stem is the bit, which chews up the formation rock and dislodges it so that drilling fluid can circulate the fragmented material back up to the surface where the circulating system filters it out of the fluid.

Drilling fluid, often called drilling mud, is a mixture of clays, chemicals and water or oil, which is carefully formulated for the particular well being drilled. Bulk storage of drilling fluid materials, the pumps and the mud-mixing equipment are placed at the start of the circulating system. Working mud pits and reserve storage are at the other end of the system. Between these two points the circulating system includes auxiliary equipment for drilling fluid maintenance and equipment for well pressure control. Within the system, the drilling mud is typically routed from the mud pits to the mud pump and from the mud pump through a standpipe and the rotary hose to the drill stem. The drilling mud travels down the drill stem to the bit, up the annular space between the drill stem and the borehole and through the blowout preventer stack to the return flow line. It then travels to a shale shaker for removal of rock cuttings, and then back to the mud pits, which are usually steel tanks. The reserve pits, usually one or two fairly shallow excavations, are used for waste material and excess water around the location.

There are numerous factors that differentiate drilling rigs, including their power generation systems, horsepower, maximum drilling depth and horizontal drilling capabilities. The actual drilling depth capability of a rig may be less than or more than its rated depth capability due to numerous factors, including the size, weight and amount of the drill pipe on the rig. The intended well depth and the drill site conditions determine the amount of drill pipe and other equipment needed to drill a well.

Our drilling rigs have rated maximum depth capabilities ranging from 12,500 feet to 20,000 feet. Of these drilling rigs, seven are electric rigs and five are mechanical rigs. An electric rig differs from a mechanical rig in that the electric rig converts the power from its generators (which in the case of mechanical rigs, power the rig directly) into electricity to power the rig. 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. Power requirements for drilling jobs may vary considerably, but most of our mechanical drilling rigs employ six engines to generate between 800 and 1,500 horsepower, depending on well depth and rig design. Most drilling rigs capable of drilling in deep formations drill to measured depths greater than 10,000 to 18,000 feet. Generally, land rigs operate with four crews of five people and two tool pushers, or rig managers, rotating on a weekly or bi-weekly schedule.

We believe that our drilling rigs and other related equipment are in good operating condition. Our employees perform periodic maintenance and minor repair work on our drilling rigs.

We obtain our contracts for drilling oil and natural gas wells either through competitive bidding or through direct negotiations with customers. We typically enter into drilling contracts that provide for compensation on a daywork basis. Occasionally, we enter into drilling contracts that provide for compensation on a footage basis, however, a majority of such footage drilling contracts also provide for daywork rates for work outside core drilling activities contemplated by such footage contracts and under certain other circumstances. We have not historically entered into turnkey contracts; however, we may decide to enter into such contracts in the future. It is also possible that we may acquire such contracts in connection with future acquisitions of drilling assets. Contract terms we offer generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, the anticipated duration of the work to be performed and market conditions.

Daywork Contracts. Under daywork drilling contracts, we provide equipment and labor and perform services under the direction, supervision and control of our customers. We are paid a specified operating daywork rate from the time the drilling unit is rigged up at the drilling location and is ready to commence operations. Additionally, the daywork drilling contracts typically provide for fees and/or a daywork rates for mobilization, demobilization, moving, standby time and for any continuous period that normal operations are suspended or cannot be carried on because of force majeure conditions. The daywork drilling contracts also generally provide that the customer has the right to designate the points at which casing will be set and the manner of setting, cementing and testing. Such specifications include hole size, casing size, weight, grade and approximate setting depth. Furthermore, the daywork drilling contracts specify the equipment, materials and services to be separately furnished by us and our customer. Under these contracts, liability is typically allocated so that our customer is solely responsible for the following: (i) damage to our surface equipment as a result of certain corrosive elements; (ii) damage to customer's equipment; (iii) damage to our in-hole equipment; (iv) damage or loss to the hole; (v) damage to the underground; and (vi) costs and damages associated with a wild well. We remain responsible for any damage to our surface equipment (except for damage resulting from the presence of certain corrosive elements) and for pollution or contamination from spills of materials that originate above the surface, are wholly in our control and are directly associated with our equipment. Daywork drilling contracts generally allow the customer to terminate the contract prior to drilling to a specified depth. This right, however, is generally subject to early termination compensation, the amount of which depends on when the termination occurs.

Footage Contracts. Under footage contracts, the contractor is typically paid a fixed amount for each foot drilled, regardless of the time required or the problems encountered in drilling the well. A majority of these types of drilling contracts, however, contain both footage and daywork basis provisions, the applicability of which typically depends on the depth of drilling and/or the type of services being performed. For instance, when drilling occurs below a specified drilling depth or when work is considered outside the scope of the footage basis, which we refer to as core drilling, then daywork contract terms apply similar to those described above. Otherwise, the footage contract terms apply. These include a footage rate price that is a specific dollar amount per linear foot of hole drilled within the contract footage depth. Also, under the footage contract terms, we assume more responsibility for base drilling activities compared to daywork drilling. For instance, in addition to assuming responsibility for damage to our surface equipment and damage caused by certain pollution and contamination, we are responsible for the following: (i) damage to our in-hole equipment; (ii) damage to the hole that is attributable to our performance; and (iii) any costs or expenditures associated with drilling a new hole after such damage. Our customers remain responsible for any loss to their equipment, for any damage to a hole caused by them and for any underground damage. As with contracts for daywork drilling, footage drilling contracts generally allow the customer to terminate the contract before drilling to a specified depth. This right, however, is generally subject to early termination compensation, the amount of which depends on when the termination occurs.

Because we assume higher risk in a footage drilling contract, we typically pay more of the out-of-pocket costs associated with such contracts as compared to daywork contracts. We endeavor to manage these additional risks through the use of our engineering expertise and bid the footage contracts accordingly. We typically maintain insurance coverage against some, but not all, drilling hazards. However, the occurrence of uninsured or under-insured losses or operating cost overruns on our footage jobs could have a negative impact on our profitability. While we have historically entered into few footage contracts, we may enter into more such arrangements in the future to the extent warranted by market conditions.

Turnkey Contracts. Turnkey contracts typically provide for a drilling company to drill a well for a customer to a specified depth and under specified conditions for a fixed price, regardless of the time required or the problems encountered in drilling the well. The drilling company would provide technical expertise and engineering services, as well as most of the equipment and drilling supplies required to drill the well. The drilling company may subcontract for related services, such as the provision of casing crews, cementing and well logging. Under typical turnkey drilling arrangements, a drilling company would not receive progress payments and would be paid by its customer only after it had performed the terms of the drilling contract in full. The risks to the drilling company under a turnkey contract are substantially greater than those under a daywork basis. This is primarily because under a turnkey contract, the drilling company assumes most of the risks associated with drilling operations generally assumed by the operator in a daywork contract, including the risk of blowout, loss of hole, stuck drill pipe, machinery breakdowns, abnormal drilling conditions and risks associated with subcontractors' services, supplies, cost escalations and personnel.

Directional Drilling. Our directional drilling services provide for the efficient drilling and production of oil and natural gas from unconventional resource plays. Our directional drilling equipment includes mud motors used to propel drill bits and kits for measurement-while-drilling, or MWD, and electromagnetic, or EM, technology. MWD kits are down-hole tools that provide real-time measurements of the location and orientation of the bottom-hole assembly, which is necessary to adjust the drilling process and guide the wellbore to a specific target. This technology, coupled with our complementary services, allows our customers to drill wellbores to specific objectives within narrow location parameters within target horizons. The evolution of unconventional resource reserve recovery has increased the need for the precise placement of a wellbore. Wellbores often travel across long-lateral intervals within narrow formations as thin as ten feet. Our personnel are involved in all aspects of a well from the initial planning of a customer's drilling program to the management and execution of the horizontal or directional drilling operation.

As of December 31, 2017, we owned seven MWD kits and three EM kits used in vertical, horizontal and directional drilling applications, 58 mud motors, ten air motors and an inventory of related parts and equipment. Currently, we perform our directional drilling services in the Utica Shale, Anadarko Basin, Arkoma Basin and Permian Basin.

Other

We also offer a variety of other energy services including coil tubing services, pressure control services, flowback services, cementing services, equipment rental services and remote accommodation services.

Coil Tubing. Coiled tubing services involve injecting coiled tubing into wells to perform various well-servicing and workover operations. Coiled tubing is a flexible steel pipe with a diameter of typically less than three inches and manufactured in continuous lengths of thousands of feet. It is wound or coiled on a truck-mounted reel for onshore applications. Due to its small diameter, coiled tubing can be inserted into existing production tubing and used to perform a variety of services to enhance the flow of oil or natural gas without using a larger, more costly workover rig. The principal advantages of using coiled tubing in a workover include the ability to (i) continue production from the well without interruption, thus reducing the risk of formation damage, (ii) move continuous coiled tubing in and out of a well significantly faster than conventional pipe in the case of a workover rig, which must be jointed and unjointed, (iii) direct fluids into a wellbore with more precision, allowing for improved stimulation fluid placement, (iv) provide a source of energy to power a downhole mud motor or manipulate down-hole tools and (v) enhance access to remote fields due to the smaller size and mobility of a coiled tubing unit. As of December 31, 2017, we had one coil tubing unit capable of running 23,000 feet of two and three eighths inch coil rated at 15,000 pounds per square inch, or psi, three coiled tubing units capable of running over 22,000 feet of two inch coil rated at 15,000 psi and two coiled tubing units capable of running over 20,000 feet of two and three eighths inch coil rated at 15,000 psi in service.

Pressure Control. Our pressure control services consist of nitrogen and fluid pumping services. Our pressure control services equipment is designed to support activities in unconventional resource plays with the ability to operate under high pressures without having to delay or cease production during completion operations. Ceasing or suppressing production during the completion phase of an unconventional well could result in formation damage impacting the overall recovery of reserves. Our pressure control services help operators minimize the risk of such damage during completion activities. As of December 31, 2017, we had a total of four nitrogen pumping units and five fluid pumping units. We provide pressure control services in the Eagle Ford Shale in South Texas and the Permian Basin in West Texas.

- ***Nitrogen Services.*** Nitrogen services involve the use of nitrogen, an inert gas, in various pressure pumping operations. When provided as a stand-alone service, nitrogen is used in displacing fluids in various oilfield applications. As of December 31, 2017, we had a total of four nitrogen pumping units capable of pumping at a rate of up to 3,000 standard cubic feet per minute with pressures up to 10,000 psi. Pumping at these rates and pressures is typically required for the unconventional oil and natural gas resource plays we serve.
- ***Fluid Pumping Services.*** Fluid pumping services consist of maintaining well pressure, pumping down wireline tools, assisting coiled tubing units and the removal of fluids and solids from the wellbore for clean-out operations. As of December 31, 2017, we had five fluid pumping units. All five are coiled tubing double pump units capable of output of up to eight barrels per minute, and are rated for pressures up to 15,000 psi.

Flowback. Our flowback services consist of production testing, solids control, hydrostatic testing and torque services. Flowback involves the process of allowing fluids to flow from the well following a treatment, either in preparation for an impending phase of treatment or to return the well to production. Our flowback equipment consists of manifolds, accumulators, valves, flare stacks and other associated equipment that combine to form up to a total of five well-testing spreads. We provide flowback services in the Appalachian Basin, the Eagle Ford Shale, the Haynesville Shale and mid-continent markets.

- ***Production Testing.*** Production testing focuses on testing production potential. Key measurements are recorded to determine activity both above and below ground. Production testing and the knowledge it provides help our customers determine where they can more efficiently deploy capital. As of December 31, 2017, we had five production testing packages.
- ***Solids Control.*** Solids control services provide prepared drilling fluids for drilling rigs with equipment such as sand separators and plug catchers. These services reduce costs throughout the entire drilling process. As of December 31, 2017, we had ten solids control packages.
- ***Hydrostatic Testing.*** Hydrostatic testing is a procedure in which pressure vessels, such as pipelines, are tested for damage or leaks. This method of testing helps maintain safety standards and increases the durability of the pipeline. We employ hydrostatic testing at industry standards and to a customer's desired specifications and configuration. As of December 31, 2017, we had two hydrostatic testing packages.
- ***Torque Services.*** Torque refers to the force applied to a rotary device to make it rotate. We offer a comprehensive range of torque services, offering a customer the dual benefit of reducing costs on the rig as well as reducing hazards for both personnel and equipment. We had five torque service packages as of December 31, 2017.

Cementing. Cementing services involve preparing and pumping cement into place in a wellbore to support and protect well casings and help achieve zonal isolation. We currently own five twin cementers and associated equipment. We provide cementing services in the Utica Shale.

Equipment Rentals. Our equipment rental services provide a wide range of oilfield related equipment used in drilling, flowback and hydraulic fracturing services. Our equipment rentals consist of light plants and other oilfield related equipment. Additionally, we provide water transfer services. We provide equipment rental and water transfer services in the Utica Shale, Eagle Ford Shale and mid-continent markets.

Remote Accommodations. Our remote accommodations business provides housing, kitchen and dining, and recreational service facilities for oilfield workers located in remote areas away from readily available lodging. We provide a turnkey solution for our customers' accommodation needs. These modular camps, when assembled together, form large dormitories, with kitchen/dining facilities and recreation areas. These camps are operated as "all inclusive," where meals are prepared and provided for the guests. The primary revenue source for these camps is lodging fees. As of December 31, 2017, we had a capacity of 1,005 rooms, 877 of which are at Sand Tiger Lodge, our camp in northern Alberta, Canada, and 128 of which are available to be leased as rental equipment to a third party.

Our Industries

Oil and Natural Gas Industry

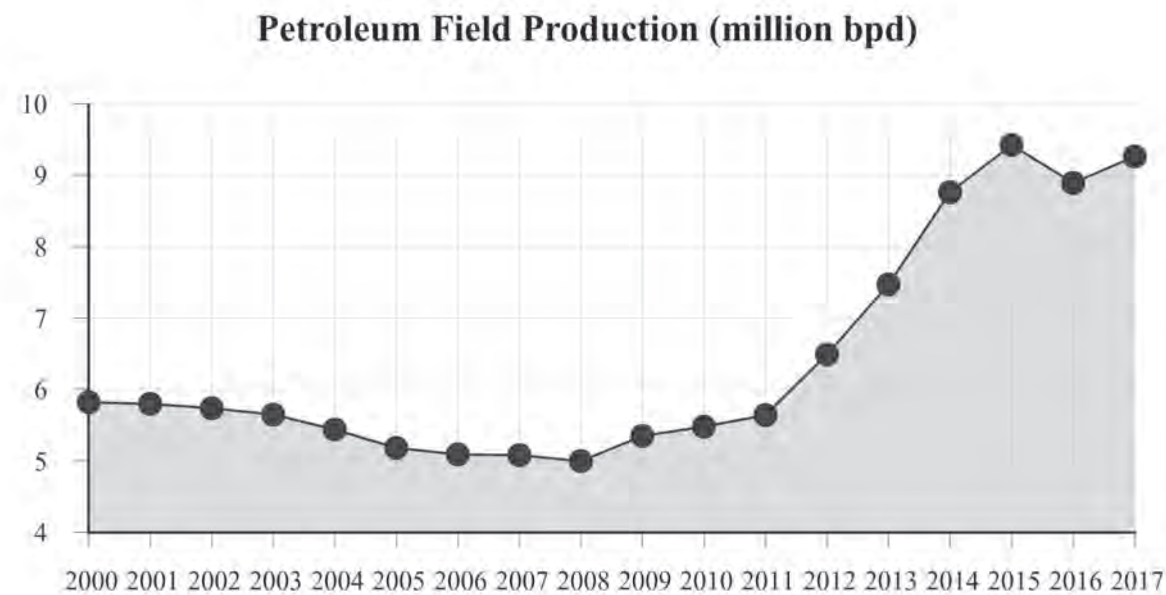
The oil and natural gas industry has traditionally been volatile and is influenced by a combination of long-term, short-term and cyclical trends, including the domestic and international supply and demand for oil and natural gas, current and expected future prices for oil and natural gas and the perceived stability and sustainability of those prices, production depletion rates and the resultant levels of cash flows generated and allocated by exploration and production companies to their drilling, completion and related services and products budget. The oil and natural gas industry is also impacted by general domestic and international economic conditions, political instability in oil producing countries, government regulations (both in the United States and elsewhere), levels of customer demand, the availability of pipeline capacity and other conditions and factors that are beyond our control.

Demand for most of our oil and natural gas products and services depends substantially on the level of expenditures by companies in the oil and natural gas industry. Oil and natural gas prices experienced a significant decline in prices that began in the third quarter of 2014 and continued into February 2016, when the closing price of oil reached a 12-year low of $26.19 per barrel on February 11, 2016. The low commodity price environment caused a reduction in the drilling, completion and other production activities of most of our customers and their spending on our products and services. During 2017, oil prices rebounded from the lows experienced in 2016 and stabilized in the $42 to $60 per barrel range.

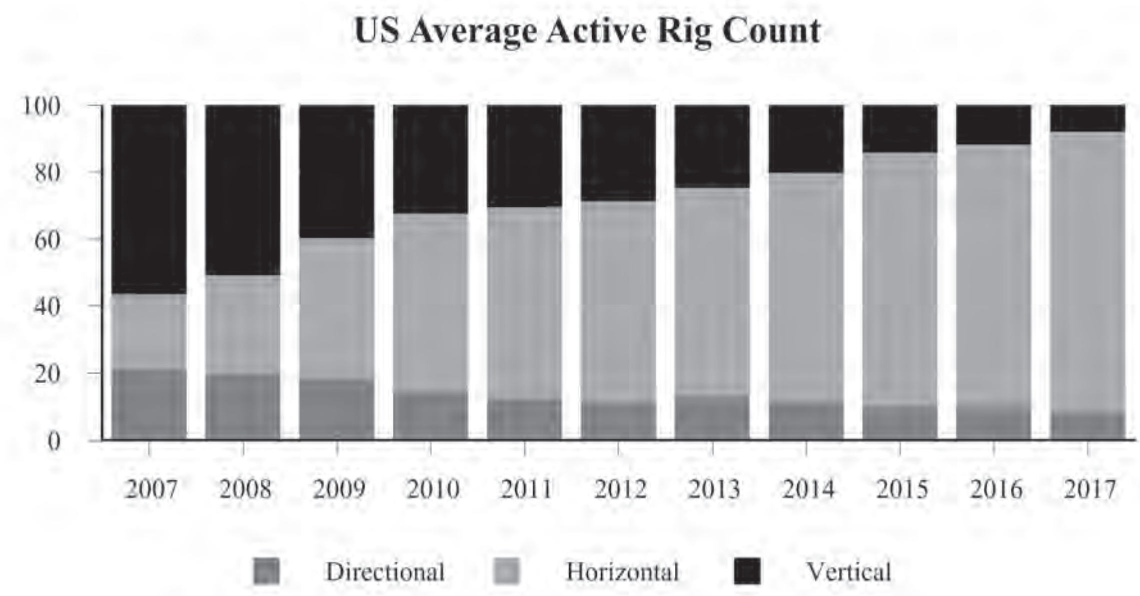
The reduction in demand, and the resulting oversupply of many of the services and products we provide, has substantially reduced the prices we can charge our customers for our products and services, and had a negative impact on the utilization of our services throughout 2016. With the rebound in oil prices from the lows experienced during the first part of 2016, the demand for our suite of services has increased. Prices for oil and natural gas historically have been extremely volatile and are expected to continue to be volatile in the years to come. Throughout 2017, the posted price for West Texas Intermediate light sweet crude oil, which we refer to as WTI, ranged from a low of $42.53 per barrel, or Bbl, on June 21, 2017 to a high of $60.42 per Bbl on December 29, 2017. The recovery in commodity prices have caused the demand for our services to increase. If near term commodity prices stabilize at current levels or continue to increase, we expect to experience further increase in demand for our services and products, particularly in our completion and production, natural sand proppant and contract land and directional drilling businesses. Spears and Associates, Inc. estimates the United States drilling industry to continue to recover in 2018, with a projected 25,000 new wells being drilled, up from approximately 23,000 in 2017. In addition, both the average lateral length drilled per well and average amount of sand pumped per well is expected to increase in 2018 as compared to 2017. We expect that the projected increased drilling activity and increase in lateral length and amount of sand pumped per well will result in increased demand for our completion and production services and natural sand proppant services.

Although the ongoing volatility and depressed levels of activity are expected to persist until supply and demand for oil and natural gas come into balance, we believe that the following trends in our industry should benefit our operations and our ability to achieve our primary business objective as commodity prices recover:

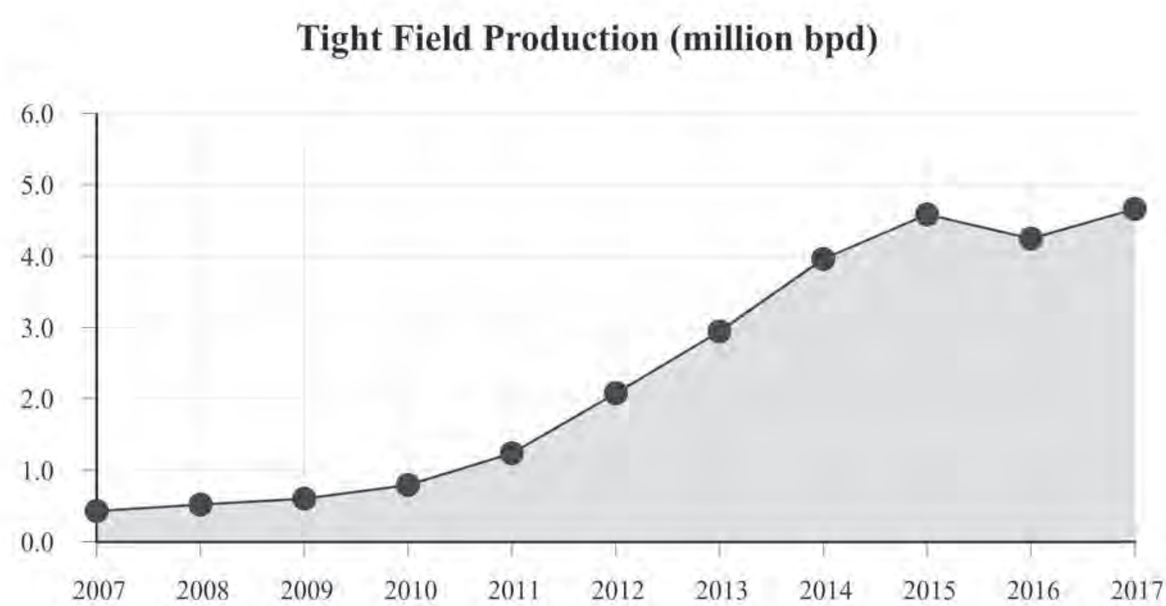
- *Increased U.S. Petroleum field Production.* According to the U.S. Energy Information Administration, or EIA, U.S. average petroleum field production was approximately 10.0 million barrels per day during November 2017, only 1.5% below the record high average daily petroleum field production set in 2015. U.S. average petroleum field production has grown at a compound annual growth rate of 9.8% over the period from 2009 through 2015 due to production gains from unconventional reservoirs. We expect that this continued growth will result in increased demand for our services as commodity prices continue to stabilize and increase.



- *Increased use of horizontal drilling to develop unconventional resource plays.* According to Baker Hughes, the horizontal rig count on December 29, 2017 was 796, or approximately 86% of the total U.S. onshore rig count. The overall onshore rig count increased significantly from May 2016 to September 2017 from 404 rigs operating to 940 rigs operating. The horizontal rig count as a percentage of the overall onshore rig count has increased every year since 2007 when horizontal rigs represented only approximately 25% of the total U.S. onshore rig count at year-end. As a result of improvements in drilling and production enhancement technologies, oil and natural gas companies are increasingly developing unconventional resources such as tight sands and shales. Successful and economic production of these unconventional resource plays frequently requires horizontal drilling, fracturing and stimulation services. Drilling related activity for unconventional resources is typically done on tighter acre spacing and thus requires that more wells be drilled relative to conventional resources. We believe that all of these characteristics will drive the demand for our services in an improved commodity price environment.



- *Tight oil production growth is expected to continue to be the primary driver of U.S. oil production growth.* According to the EIA, U.S. tight oil production grew from approximately 430,000 barrels per day in 2007 to over 4.6 million barrels per day in 2017, representing approximately 50% of total U.S. crude oil production in 2017. A majority of this increase came from the Eagle Ford play in South Texas, the SCOOP/STACK plays in the mid-continent of Oklahoma, the Bakken Shale in the Williston Basin of North Dakota and Montana, and the Permian Basin in West Texas. We believe the Utica Shale and the Permian Basin, our primary business locations, will be key drivers of U.S. tight oil and natural gas production as those plays are developed further in the coming years due to the favorable well economics in those basins.



- *Horizontal wells are heavily dependent on oilfield services.* According to Baker Hughes, as of December 29, 2017, horizontal rigs accounted for approximately 86% of all rigs drilling in the United States, up from 25% at year-end 2007. The scope of services for a horizontal well are greater than for a conventional well. Industry analysts report that the average horsepower, length of the lateral and number of fracture stages has continued to increase since 2008. We believe our commitment to provide services in unconventional plays, such as the Utica Shale and the Permian Basin, provide us the opportunity to compete in those regional markets where the majority of total footage is drilled each year in the United States.

- *New and emerging unconventional resource plays.* In addition to the development of existing unconventional resource plays such as the Permian, Utica, Bakken, Eagle Ford, Barnett, Fayetteville, Cotton Valley, Haynesville, Marcellus and Woodford Shales, exploration and production companies continue to find new unconventional resources. These include oil and liquids-based shales in the Cana Woodford, Granite Wash, Niobrara, Woodford and SCOOP/STACK resource plays. In certain cases, exploration and production companies have acquired vast acreage positions in these plays that require them to drill and produce hydrocarbons to hold the leased acreage. We believe these unconventional resource plays will increasingly drive demand for our services as commodity prices continue to recover as they typically require the use of extended reach horizontal drilling, multiple stage fracture stimulation and high pressure completion capabilities. We also believe we are well positioned to expand our services in two major unconventional plays, the Utica Shale in Ohio and the Permian Basin in West Texas.

- *Need for additional drilling activity to maintain production levels.* With the increased maturity of the onshore conventional and, in many cases, unconventional resource plays, oil and natural gas production may be characterized as having steeper initial decline curves. Given average decline rates and the substantial reduction in activity over the past year, we believe that the number of wells drilled is likely to increase in coming years as commodity prices continue to recover. Once a well has been drilled, it requires recurring production and completion services, which we believe will also drive demand for our services.

Electric Infrastructure Industry

The electrical infrastructure industry involves the construction and maintenance of the electrical power grid, including, but not limited to, power generation, high voltage transmission lines, substations and low voltage distribution lines, all of which connect power generation facilities to end users. The industry also provides storm repair and restoration services in response to storms and other disasters, including hurricanes Harvey, Irma and Maria. The industry is highly fragmented with more than 3,000 separate utility companies identified in the United States in 2016, spread across the following subgroups: IOUs, private utilities and Co-Ops.

Demand for our services is driven by the construction of transmission lines, substations and distribution networks and is determined by the level of expenditures of utility companies. While expansion of the electrical grid is occurring, the majority of capital expenditures spent in recent years has surrounded the repair and maintenance of existing networks. Another factor that significantly influences the level of spending in the industry are natural disasters, which impact the electrical grid. These natural disasters include, but are not limited to, thunderstorms, ice storms, snow storms, hurricanes, earthquakes, wildfires and lightning strikes.

Certain barriers to entry exist in the markets in which we operate, including adequate financial resources, technical expertise, high safety ratings and a proven track record of operational success. We compete based upon our industry experience, technical expertise, financial and operational resources, geographic presence, industry reputation, our safety record and customer service. While we believe our customers consider a number of factors when selecting a service provider, they award most of their work through a bid process, although our work with PREPA has not been obtained through a formal bid process. Consequently, price is often a principal factor in determining which service provider is selected.

We believe that the age of the existing infrastructure across the United States and the spending trends in North America will benefit our operations and our ability to achieve our business objectives.

Natural Sand Proppant Industry

Demand growth for frac sand and other proppants is primarily driven by advancements in oil and natural gas drilling and well completion technology and techniques, such as horizontal drilling and hydraulic fracturing, as well as overall industry activity growth. These advancements have made the extraction of oil and natural gas increasingly cost-effective in formations that historically would have been unprofitable to develop, resulting in a greater number of wells being drilled. Demand for proppant declined in 2015 and throughout most of 2016 with reduced well completion activity; however, we believe that demand for proppant will continue to grow, as it did throughout 2017, over the long-term, primarily driven by the increase in the average amount of proppant consumed per horizontal rig and as a result of the following demand drivers:

- improvements in drilling rig productivity (from, among other things, pad drilling), resulting in more wells drilled per rig per year;
- increases in the number of wells drilled per acre;
- increases in the length of the typical horizontal wellbore;
- increases in the number of fracture stages per lateral foot in the typical completed horizontal wellbore;

- increases in the volume of proppant used per fracturing stage; and
- recurring efforts to offset steep production declines in unconventional oil and natural gas reservoirs, including the drilling of new wells and secondary hydraulic fracturing of existing wells.

As demand for raw frac sand increased dramatically through 2014, the supply of raw frac sand failed to keep pace, resulting in a supply-demand disparity. As a result, a number of existing and new competitors announced supply expansions and greenfield projects. However, there are several key geological, operational and economic constraints to increasing raw frac sand production on an industry-wide basis, including:

- the difficulty of finding frac sand reserves that meet API specifications and consisting of the mesh size in demand;
- the difficulty of securing contiguous frac sand reserves large enough to justify the capital investment required to develop a processing facility with a higher base of fixed costs;
- the challenges of identifying frac sand reserves with the above characteristics that either are located in close proximity to oil and natural gas reservoirs or have rail access needed for low-cost transportation to major shale basins;
- the hurdles of securing mining, production, water, air, refuse and other federal, state and local operating permits from the proper authorities;
- local opposition to development of facilities, especially those that require the use of on-road transportation, including hours of operations and noise level restrictions, in addition to moratoria on raw frac sand facilities in multiple counties in Wisconsin and other states which hold potential sand reserves; and
- the typically long lead time required to design and construct sand processing facilities that can efficiently process large quantities of high quality frac sand.

As a result of the decline in oil and natural gas exploration and production activity that took place in 2015 and throughout most of 2016, many frac sand suppliers significantly delayed or canceled their expansion or greenfield projects. In addition, several existing facilities were temporarily or permanently idled, often due to high cost of production.

In 2017, several new and existing suppliers announced planned capacity additions of frac sand supply, particularly in the Permian Basin. We expect frac sand supply to lag growth in demand over the coming months and quarters. While planned capacity may exceed the expectations for frac sand demand, the collectively available industry capacity is constrained due to (i) availability of the grades of sand that are currently in demand, (ii) general operating conditions and normal downtime and (iii) logistics constraints. The industry is expected to add capacity over the next 12 to 18 months, particularly in the Permian Basin; however, we do not expect such supply to be available in the volume grades or timeframe needed to efficiently meet the increasing demand.

Our proppant sand reserves consist of Northern White silica sand, giving us access to a range of high-quality sand grades meeting or exceeding all API specifications, including a mix between concentrations of coarse grades (20/40 and 30/50 mesh size) and finer grades (40/70 and 100 mesh size). Our sample boring data and our historical production data have indicated that our reserves contain deposits of approximately 40% 40 mesh size or coarser substrate. The coarseness and conductivity of Northern White frac sand significantly enhances recovery of oil and liquids-rich gas by allowing hydrocarbons to flow more freely than is sometimes possible with native sand. The low acid-solubility increases the integrity of Northern White frac sand relative to other proppants with higher acid-solubility, especially in shales where hydrogen sulfide and other acidic chemicals are co-mingled with the targeted hydrocarbons. In addition, its crush resistant properties enable Northern White frac sand to be used in deeper drilling applications than the frac sand produced from many native mineral deposits.

We believe that the coarseness, conductivity, sphericity, acid-solubility, and crush-resistant properties of our Northern White sand reserves and our facilities' connectivity to rail and other transportation infrastructure afford us an advantage over our competitors and make us one of a select group of sand producers capable of delivering high volumes of frac sand that is optimal for oil and natural gas production to all major unconventional resource basins currently producing throughout North America.

Our Strengths

Our primary business objective is to grow our operations and create value for our stockholders through organic growth opportunities and accretive acquisitions. We believe that the following strengths position us well to capitalize on activity in unconventional resource plays and achieve our primary business objective:

- *Modern fleet of hydraulic fracturing equipment designed for horizontal wells*. Our service fleet is predominantly comprised of equipment designed to optimize recovery from unconventional wells. Three of our pressure pumping fleets with total combined horsepower of 132,500 were built in 2017 and our other three fleets with a total combined horsepower of 159,250 have an average age of approximately four years. We believe that our modern fleet of quality equipment will allow us to provide a high level of service to our customers and capitalize on future growth in the unconventional resource plays that we serve.

- *Strategic geographic positioning, including primary presence in the Utica Shale and the Permian Basin.* We currently operate facilities and service centers to support our operations in major unconventional resource plays in the United States, including the Utica Shale in Eastern Ohio, the Permian Basin in West Texas, the SCOOP/STACK in Oklahoma, the Marcellus Shale in West Virginia, the Granite Wash in Oklahoma and Texas, the Cana Woodford Shale and the Cleveland Sand in Oklahoma, the Eagle Ford Shale in South Texas and the oil sands in Alberta, Canada. We believe our geographic positioning within active oil and natural gas liquids resource plays will benefit us strategically as activity increases in these unconventional resource plays.

- *Long-term contractual and other regional relationships with a stable customer base.* We are party to two four-year contracts with Gulfport to provide pressure pumping services and natural sand proppant services through September 2018. In addition, our operational division heads and field managers have formed long-term relationships with our customer base. We believe these contractual and other relationships help provide us a more stable and growth-oriented client base in the unconventional shale markets as well as the infrastructure markets that we currently serve. Our customers include large independent oil and natural gas exploration and production companies, government-funded utilities, private utilities, public IOUs and Co-Ops. Our top five customers for the year ended December 31, 2017, representing 71% of our revenue were Gulfport, PREPA, Newfield, Rice Energy and Surge Operating. For the year ended December 31, 2016, our top five customers, representing 80% of our revenue, were Gulfport, Oil Sands Limited, Rice Energy, Surge Operating and Hilcorp.

- *Experienced management and operating team.* Our operational division heads have an extensive track record in the oilfield and infrastructure service businesses with an average of over 35 years of oilfield services experience and over 25 years of infrastructure services experience. In addition, our field managers have expertise in the areas in which they operate and understand the regional challenges that our customers face. We believe their knowledge of our industries and business lines enhances our ability to provide innovative, client-focused and basin-specific customer service, which we also believe strengthens our relationships with our customers.

Our Business Strategy

We intend to achieve our primary business objective by the successful execution of our business plan to strategically deploy our equipment and personnel to provide pressure pumping services, natural sand proppant services, contract land and directional drilling services and other energy services in unconventional resource plays, including the Utica Shale in Ohio, the SCOOP/STACK in Oklahoma and the Permian Basin in West Texas. In the case of our infrastructure services businesses, we intend to achieve our primary business objective by the successful execution of our business plan to strategically deploy equipment and personnel to provide infrastructure services in Puerto Rico as well as the northeast, southwest and midwest portions of the United States. We believe our oil and natural gas services optimize our customers' ultimate resources recovery and present value of hydrocarbon reserves and that our infrastructure services optimize our customers' ability to maintain, improve and expand their infrastructure. We seek to create cost efficiencies for our customers by providing a suite of complementary services designed to address a wide range of our customers' needs. Specifically, we intend to create value for our stockholders through the following strategies:

- *Capitalize on the recovery in activity in the unconventional resource plays.* Our oil and natural gas service equipment is designed to provide a broad range of services for unconventional wells, and our operations are strategically located in major unconventional resource plays. During 2017, the posted price for WTI stabilized and increased following the significant declines experienced in 2016. The average price per barrel in 2017 was $50.97 with a low of $42.53 per barrel on June 21, 2017 to a high of $60.42 per barrel on December 29, 2017. If commodity prices stabilize at current levels or recover further, we expect to experience further increase in demand for our services and products. We intend to capitalize on the anticipated increase in activity in these markets and diversify our operations across additional unconventional resource basins. Our core operations are currently focused in the Utica Shale in Ohio, the SCOOP/STACK in Oklahoma and the Permian Basin in West Texas. We intend to continue to strategically deploy assets to these and other unconventional resource basins and will look to capitalize on further growth in emerging unconventional resource plays as they develop.

- *Leverage our broad range of services for unconventional wells for cross-selling opportunities.* We offer a complementary suite of services and products. Our pressure pumping and well services activities provide hydraulic fracturing services for unconventional wells. Our infrastructure services division provides construction, upgrade, maintenance and repair services to the electrical infrastructure industry. Our natural sand proppant services division mines, processes and sells natural sand proppant for hydraulic fracturing. Our drilling services division adds drilling capabilities to our well-related services. Additionally, we provide coil tubing services, pressure control services, flowback services, cementing services, equipment rental and remote accommodations. We intend to leverage our existing customer relationships and operational track record to cross sell our services and increase our exposure and product offerings to our existing customers, broaden our customer base and expand opportunistically to other geographic regions in which our customers have operations, as well as to create operational efficiencies for our customers.

- *Expand through selected, accretive acquisitions.* To complement our organic growth, we intend to actively pursue selected, accretive acquisitions of businesses and assets, primarily related to our completion and production services, infrastructure services and natural sand proppant services, that can meet our targeted returns on invested capital and enhance our portfolio of products and services, market positioning and/or geographic presence. We believe this strategy will facilitate the continued expansion of our customer base, geographic presence and service offerings. We also believe that our industry contacts and those of Wexford, our equity sponsor and largest stockholder, may be helpful to facilitate the identification of acquisition opportunities. We may use our common stock as consideration for accretive acquisitions.

- *Maintain a conservative balance sheet.* We seek to maintain a conservative balance sheet, which allows us to better react to changes in commodity prices and related demand for our services, as well as overall market conditions. We used a portion of the net proceeds from the IPO to repay all outstanding borrowings under our revolving credit facility, and as of December 31, 2016, had no outstanding debt. During 2017, we used borrowings under our revolving credit facility to fund $133.9 million in capital expenditures and three accretive acquisitions, and as of December 31, 2017, had outstanding debt totaling $99.9 million and a cash balance of $5.6 million. We intend to use a portion of our cash flows from operations to reduce our outstanding debt in 2018.

- *Expand our services to meet expanding customer demand.* The scope of services for horizontal wells is greater than that for conventional wells. Industry analysts have reported that the average horsepower required for current completion designs, amount of sand per lateral foot, length of lateral and number of fracture stages has continued to increase since 2008. We consistently monitor market conditions and intend to expand the capacity and scope of our business lines as demand warrants in resource plays in which we currently operate, as well as in new resource plays. If we perceive unmet demand in our principal geographic locations for different service lines, we will seek to expand our current service offerings to meet that demand.

- *Expand our energy infrastructure business unit in the Lower 48 and in Puerto Rico.* Industry analysts have reported that spending in the T&D industry will exceed $60 billion each year through 2022. We consistently monitor market conditions and intend to expand the capacity and scope of our energy infrastructure services as demand warrants in geographic areas in which we currently operate, as well as in new geographic areas.

- *Leverage our experienced operational management team expertise.* We seek to manage the services we provide as closely as possible to the needs of our customer base. Our operational division heads have long-term relationships with our largest customers. We intend to leverage these relationships and our operational management team's expertise to deliver innovative, client focused and services to our customers.

Marketing and Customers

Our customers consist primarily of independent oil and natural gas producers, government-funded utilities, private utilities, IOUs, Co-Ops and land-based drilling contractors in North America. For the years ended December 31, 2017 and 2016, we had approximately 364 and 239 customers, respectively, including Gulfport, PREPA, Newfield, Rice Energy and Surge Operating. Our top five customers accounted for approximately 71%, 80%, and 71%, respectively, of our revenue for the years ended December 31, 2017, 2016 and 2015. During the year ended December 31, 2017, Gulfport and PREPA accounted for 30% and 29%, respectively, of our revenue. For the year ended December 31, 2016, Gulfport and Oil Sands Limited accounted for 57% and 11%, respectively, of our revenue. For the year ended December 31, 2015, Gulfport and EQT Production Company accounted for 46% and 12%, respectively, of our revenue. Although we believe we have a broad customer base and wide geographic coverage of operations, it is likely that we will continue to derive a significant portion of our revenue from a relatively small number of customers in the future. If a major customer decided not to continue to use our services, revenue could decline and our operating results and financial condition could be harmed.

Operating Risks and Insurance

Our operations are subject to hazards inherent in the energy services industry, such as accidents, blowouts, explosions, fires and spills and releases that can cause:

- personal injury or loss of life;
- damage or destruction of property, equipment, natural resources and the environment; and
- suspension of operations.

In addition, claims for loss of oil and natural gas production and damage to formations can occur in the oilfield services industry. If a serious accident were to occur at a location where our equipment and services are being used, it could result in us being named as a defendant in lawsuits asserting large claims.

Because our business involves the transportation of heavy equipment and materials, we may also experience traffic accidents which may result in spills, property damage and personal injury.

Despite our efforts to maintain safety standards, we from time to time have suffered accidents in the past and anticipate that we could experience accidents in the future. In addition to the property damage, personal injury and other losses from these accidents, the frequency and severity of these incidents affect our operating costs and insurability and our relationships with customers, employees, regulatory agencies and other parties. Any significant increase in the frequency or severity of these incidents, or the general level of compensation awards, could adversely affect the cost of, or our ability to obtain, workers' compensation and other forms of insurance, and could have other material adverse effects on our financial condition and results of operations.

We maintain commercial general liability, workers' compensation, business auto, commercial property, motor truck cargo, umbrella liability, in certain instances, excess liability, and directors and officers insurance policies providing coverages of risks and amounts that we believe to be customary in our industry. With respect to our hydraulic fracturing operations, coverage would be available under our policy for any surface or subsurface environmental clean-up and liability to third parties arising from any surface or subsurface contamination. We also have certain specific coverages for some of our businesses, including our remote accommodation services, pressure pumping services and contract and directional drilling services.

Although we maintain insurance coverage of types and amounts that we believe to be customary in the industry, we are not fully insured against all risks, either because insurance is not available or because of the high premium costs relative to perceived risk. Further, insurance rates have in the past been subject to wide fluctuation and changes in coverage could result in less coverage, increases in cost or higher deductibles and retentions. Liabilities for which we are not insured, or which exceed the policy limits of our applicable insurance, could have a material adverse effect on us. See Item 1A. "Risk Factors" on page 23 of this annual report for a description of certain risks associated with our insurance policies.

Safety and Remediation Program

In the energy services industry, an important competitive factor in establishing and maintaining long-term customer relationships is having an experienced and skilled workforce. Many of our large customers place an emphasis not only on pricing, but also on safety records and quality management systems of contractors. We have committed resources toward employee safety and quality management training programs. Our field employees are required to complete both technical and safety training programs. Further, as part of our safety program and remediation procedures, we check treating iron for any defects on a periodic basis to avoid iron failure during hydraulic fracturing operations, marking such treating iron to reflect the most recent testing date. We also regularly monitor pressure levels in the treating iron used for fracturing and the surface casing to verify that the pressure and flow rates are consistent with the job specific model in an effort to avoid failure. As part of our safety procedures, we also have the capability to shut down our pressure pumping and fracturing operations both at the pumps and in our data van. In addition, we maintain spill kits on location for containment of pollutants that may be spilled in the process of providing our hydraulic fracturing services. The spill kits are generally comprised of pads and booms for absorption and containment of spills, as well as soda ash for neutralizing acid. Fire extinguishers are also in place on job sites at each pump.

Historically, we have used third-party contractors to provide remediation and spill response services when necessary to address spills that were beyond our containment capabilities. None of these prior spills were significant, and we have not experienced any incidents, citations or legal proceeding relating to our hydraulic fracturing services for environmental concerns. To the extent our hydraulic fracturing or other energy services operations result in a future spill, leak or other environmental impact that is beyond our ability to contain, we intend to engage the services of such remediation company or an alternative company to assist us with clean-up and remediation.

Competition

The markets in which we operate are highly competitive. To be successful, a company must provide services and products that meet the specific needs of oil and natural gas exploration and production companies, drilling services contractors, government-funded utilities, private utilities, IOUs and Co-Ops at competitive prices.

We provide our services and products across the United States, Puerto Rico and in Alberta, Canada and we compete against different companies in each service and product line we offer. Our competition includes many large and small energy service companies, including the largest integrated oilfield services companies and energy infrastructure companies. Our major competitors in pressure pumping services include Halliburton Company, U.S. Well Services, LLC, Schlumberger Limited, Keane Group, Inc., C&J Energy Services Ltd., RPC Incorporated, Complete Energy Services, Inc., Liberty Oilfield Services, Inc. and FTS International, Inc. Our major competitors for our infrastructure services business include MYR Group, Inc, Quanta Services, Inc, MasTec, Inc. and EMCOR Group, Inc. Our major competitors in our natural sand proppant production and sales business are Badger Mining Corporation, Fairmount Minerals, Ltd., Hi-Crush Partners LP, Preferred Proppants LLC, Unimin Corporation, Smart Sand, Inc., Emerge Energy Services LP and U.S. Silica Holdings Inc. In our contract land and directional drilling services segment, our primary competitors include Helmerich & Payne, Inc., Precision Drilling Corporation, Patterson-UTI Energy, Inc., Cactus Drilling, Sidewinder Drilling, Inc., Baker Hughes Incorporated, Weatherford International Ltd. and various regional and local service providers.

We believe that the principal competitive factors in the market areas that we serve are quality of service and products, reputation for safety and technical proficiency, availability and price. While we must be competitive in our pricing, we believe our customers select our services and products based on the local leadership and expertise that our field management and operating personnel use to deliver quality services and products.

Regulation

We operate under the jurisdiction of a number of regulatory bodies that regulate worker safety standards, the handling of hazardous materials, the transportation of explosives, the protection of human health and the environment and driving standards of operation. Regulations concerning equipment certification create an ongoing need for regular maintenance which is incorporated into our daily operating procedures. The oil and natural gas and infrastructure industries are subject to environmental and other regulation pursuant to local, state and federal legislation.

Transportation Matters

In connection with our transportation and relocation of our equipment and shipment of frac sand, we operate trucks and other heavy equipment. As such, we operate as a motor carrier in providing certain of our services and therefore are subject to regulation by the United States Department of Transportation and by various state agencies. These regulatory authorities exercise broad powers, governing activities such as the authorization to engage in motor carrier operations, driver licensing and insurance requirements, financial reporting and review of certain mergers, consolidations and acquisitions, and transportation of hazardous materials (HAZMAT). Our trucking operations are subject to possible regulatory and legislative changes that may increase our costs. Some of these possible changes include increasingly stringent environmental regulations, changes in the hours of service regulations which govern the amount of time a driver may drive or work in any specific period, onboard black box recorder device requirements or limits on vehicle weight and size.

Interstate motor carrier operations are subject to safety requirements prescribed by the Federal Motor Carrier Safety Administration, or FMCSA, a unit within the United States Department of Transportation. To a large degree, intrastate motor carrier operations are subject to state safety regulations that mirror federal regulations. Matters such as the weight and dimensions of equipment are also subject to federal and state regulations. From time to time, various legislative proposals are introduced, including proposals to increase federal, state or local taxes, including taxes on motor fuels, which may increase our costs or adversely impact the recruitment of drivers. We cannot predict whether, or in what form, any increase in such taxes applicable to us will be enacted.

Certain motor vehicle operators require registration with the Department of Transportation. This registration requires an acceptable operating record. The Department of Transportation periodically conducts compliance reviews and may revoke registration privileges based on certain safety performance criteria which could result in a suspension of operations. The rating scale consists of “satisfactory,” “conditional” and “unsatisfactory” ratings. As of December 31, 2017, all of our trucking operations have “satisfactory” ratings with the Department of Transportation. We have undertaken comprehensive efforts that we believe are adequate to comply with the regulations. Further information regarding our safety performance is available at the FMCSA website at www.fmcsa.dot.gov.

In December 2010, the FMCSA launched a program called Compliance, Safety, Accountability, or CSA, in an effort to improve commercial truck and bus safety. A component of CSA is the Safety Measurement System, or SMS, which analyzes all safety violations recorded by federal and state law enforcement personnel to determine a carrier’s safety performance. The SMS is intended to allow FMCSA to identify carriers with safety issues and intervene to address those problems. However, the agency has announced a future intention to revise its safety rating system by making greater use of SMS data in lieu of on-site compliance audits of carriers. At this time, we cannot predict the effect such a revision may have on our safety rating.

Environmental Matters and Regulation

Our operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous federal, state and local governmental agencies, such as the U.S. Environmental Protection Agency, or the EPA, issue regulations that often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically or seismically sensitive areas and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or related to our owned or operated facilities. Liability under such laws and regulations is strict (i.e., no showing of “fault” is required) and can be joint and several. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry and infrastructure industry in general. We have not experienced any material adverse effect from compliance with these environmental requirements. This trend, however, may not continue in the future.

Waste Handling. We handle, transport, store and dispose of wastes that are subject to the federal Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes and regulations promulgated thereunder, which affect our activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although certain petroleum production wastes are exempt from regulation as hazardous wastes under RCRA, such wastes may constitute “solid wastes” that are subject to the less stringent requirements of non-hazardous waste provisions.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. Moreover, the EPA or state or local governments may adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as “hazardous wastes.” Several environmental organizations have also petitioned the EPA to modify existing regulations to recategorize certain oil and natural gas exploration, development and production wastes as “hazardous.” Also, in December 2015, the EPA agreed in a consent decree to review its regulation of oil and gas waste. It has until March 2019 to determine whether any revisions are necessary. Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses. Although we do not believe the current costs of managing our wastes, as presently classified, to be significant, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Remediation of Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, which we refer to as CERCLA, or the “Superfund” law, and analogous state laws, generally imposes liability, without regard to fault or legality of the original conduct, on classes of persons who are considered to be responsible for the release of a “hazardous substance” into the environment. These persons include the current owner or operator of a contaminated facility, a former owner or operator of the facility at the time of contamination and those persons that disposed or arranged for the disposal of the hazardous substance at the facility. Under CERCLA and comparable state statutes, persons deemed “responsible parties” are subject to strict liability, that, in some circumstances, may be joint and several for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we use materials that, if released, would be subject to CERCLA and comparable state statutes. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA and comparable state statutes for all or part of the costs to clean up sites at which such “hazardous substances” have been released.

NORM. In the course of our operations, some of our equipment may be exposed to naturally occurring radioactive materials associated with oil and gas deposits and, accordingly may result in the generation of wastes and other materials containing naturally occurring radioactive materials, or NORM. NORM exhibiting levels of naturally occurring radiation in excess of established state standards are subject to special handling and disposal requirements, and any storage vessels, piping and work area affected by NORM may be subject to remediation or restoration requirements. Because certain of the properties presently or previously owned, operated or occupied by us may have been used for oil and gas production operations, it is possible that we may incur costs or liabilities associated with NORM.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the “Clean Water Act,” the Safe Drinking Water Act, the Oil Pollution Act and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers, which we refer to as the Corps. In September 2015, a new EPA and the Corps rule defining the scope of the jurisdiction of the EPA and the Corps over wetlands and other waters became effective. To the extent the rule expands the range of properties subject to the Clean Water Act’s jurisdiction, certain energy companies could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. The rule has been challenged in court on the grounds that it unlawfully expands the reach of Clean Water Act programs, and implementation of the rule has been stayed pending resolution of the court challenge. In the interim, the EPA and the Corps have resumed nationwide application of the agencies’ prior regulations defining the term “waters of the United States.” Further, on February 28, 2017, President Trump signed an executive order directing the relevant executive agencies to review the rules and to initiate rulemaking to rescind or revise them, as appropriate under the stated policies of protecting navigable waters from pollution while promoting economic growth, reducing uncertainty, and showing due regard for Congress and the states. On July 27, 2017, the EPA and the Corps published a proposed rule to rescind the 2015 rules, and, on November 22, 2017, the agencies published a proposed rule to maintain the status quo pending the agencies review of the 2015 rules.

The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. In addition, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants, which regulations are discussed in more detail below under the caption “—Regulation of Hydraulic Fracturing.” Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Also, spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Noncompliance with these requirements may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations.

Air Emissions. The federal Clean Air Act, as amended, and comparable state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. For example, our sand proppant production operations are subject to air permits issued by the Wisconsin Department of Natural Resources regulating our emission of fugitive dust and other constituents. These and other laws and regulations may increase the costs of compliance for some facilities where we operate, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Obtaining or renewing permits has the potential to delay the development of oil and natural gas and infrastructure projects.

Climate Change. In December 2009, the EPA issued an Endangerment Finding that determined that emissions of carbon dioxide, methane and other greenhouse gases, or collectively referred to as GHGs, present an endangerment to public health and the environment because, according to the EPA, emissions of such gases contribute to the warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. Subsequently, the EPA adopted two sets of related rules, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. The EPA adopted the stationary source rule, which we refer to as the tailoring rule, in May 2010, and it became effective January 2011. The tailoring rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the PSD and Title V programs of the Clean Air Act. On June 23, 2014, in Utility Air Regulatory Group v. EPA, the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On August 26, 2016, the EPA proposed changes needed to bring EPA's air permitting regulations in line with the Supreme Court's decision on GHG permitting. The proposed rule was published in the Federal Register on October 3, 2016 and the public comment period closed on December 2, 2016.

Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA expanded the GHG reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our customers' facilities, beginning in 2012 for emissions occurring in 2011. In October 2015, the EPA amended the GHG reporting rule to add the reporting of GHG emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of GHGs and almost one-half of the states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Although the U.S. Congress has not adopted such legislation at this time, it may do so in the future and many states continue to pursue regulations to reduce GHG emissions. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of such allowances is expected to escalate significantly.

In December 2015, the United States participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of greenhouse gases. The Agreement went into effect on November 4, 2016. The Paris Agreement establishes a framework for the parties to cooperate and report actions to reduce greenhouse gas emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement, and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Restrictions on emissions of methane or carbon dioxide that may be imposed could adversely affect the oil and natural gas industry by reducing demand for hydrocarbons and by making it more expensive to develop and produce hydrocarbons, either of which could have a material adverse effect on future demand for our services. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business.

In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Furthermore, claims have been made against certain energy companies alleging that greenhouse gas emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public companies may seek to enforce environmental laws and regulations against certain energy companies and could allege personal injury, property damages, or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Moreover, climate change may cause more extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels and increased volatility in seasonal temperatures. Extreme weather conditions can interfere with our productivity and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

Endangered Species Act

Environmental laws such as the Endangered Species Act, as amended, or the ESA, may impact exploration, development and production activities on public or private lands. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the U.S. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Federal agencies are required to insure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. The U.S. Fish and Wildlife Service may identify, however, previously unidentified endangered or threatened species or may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species, which could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Regulation of Hydraulic Fracturing

A portion of our business is dependent on our ability to conduct hydraulic fracturing and horizontal drilling activities. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process, which involves the injection of water, sand and chemicals (also called “proppants”) under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as “Class II” Underground Injection Control wells under the Safe Drinking Water Act. In addition, the EPA previously announced its plans to develop a Notice of Proposed Rulemaking by June 2018, which would describe a proposed mechanism - regulatory, voluntary, or a combination of both - to collect data on hydraulic fracturing chemical substances and mixtures. Also, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plans. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and natural gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities and the environmental impacts of discharges from CWT facilities. Furthermore, legislation to amend the Safe Drinking Water Act, or SDWA, to repeal the exemption for hydraulic fracturing (except when diesel fuels are used) from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress.

On August 16, 2012, the EPA published final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA’s rule package includes New Source Performance standards, which we refer to as NSP standards, to address emissions of sulfur dioxide and volatile organic compounds and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rules seek to achieve a 95% reduction in volatile organic compounds emitted by requiring the use of reduced emission completions or “green completions” on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. In particular, on May 12, 2016, the EPA amended the NSP standards to impose new standards for methane and VOC emissions for certain new, modified and reconstructed equipment, processes and activities across the oil and natural gas sector. However, in a March 28, 2017 executive order, President Trump directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation's energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. On June 16, 2017, the EPA published a proposed rule to stay for two years certain requirements of the 2016 regulations, including fugitive emission requirements. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions.

In addition, on March 26, 2015, the Bureau of Land Management, or BLM, published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. On June 21, 2016, the United States District Court for Wyoming set aside the rule, holding that the BLM lacked Congressional authority to promulgate the rule. The BLM has appealed the decision to the Tenth Circuit Court of Appeals. Also, on November 15, 2016, the BLM finalized a rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The rule requires operators to use currently available technologies and equipment to reduce flaring, periodically inspect their operations for leaks, and replace outdated equipment that vents large quantities of gas into the air. The rule also clarifies when operators owe the government royalties for flared gas. State and industry groups have challenged this rule in federal court, asserting that the BLM lacks authority to prescribe air quality regulations. On March 28, 2017, President Trump signed an executive order directing the BLM to review the above rules and, if appropriate, to initiate a rulemaking to rescind or revise them. Accordingly, on December 29, 2017, the BLM published a final rule to rescind the 2015 hydraulic fracturing rule. Also, on December 8, 2017, the BLM published a final rule to suspend or delay certain requirements of the 2016 methane rule until January 17, 2019. Further legal challenges are expected. At this time, it is uncertain when, or if, the rules will be implemented, and what impact they would have on our operations.

There are certain governmental reviews either underway or being proposed that focus on the environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and whether any meaningful results are obtained, could spur initiatives to further regulate hydraulic fracturing, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

Several states and local jurisdictions in which we or our customers operate have adopted or are considering adopting regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. Any increased regulation of hydraulic fracturing could reduce the demand for our services and materially and adversely affect our reserves and results of operations.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, induced seismic activity, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as 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 could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal, state or local level, our customers' fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative or regulatory changes could cause us or our customers to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal, state or local laws governing hydraulic fracturing.

Regulation of Infrastructure Services

In our infrastructure business, our operations are subject to various federal, state and local laws and regulations including:

- licensing, permitting and inspection requirements applicable to contractors, electricians and engineers;
- regulations relating to worker safety;
- permitting and inspection requirements applicable to construction projects;
- wage and hour regulations;
- building and electrical codes; and
- special bidding, procurement and other requirements on government projects.

We believe that we have all the licenses required to conduct our energy infrastructure services and that we are in substantial compliance with applicable regulatory requirements. Our failure to comply with applicable regulations could result in substantial fines or revocation of our operating licenses, as well as give rise to termination or cancellation rights under our contracts or disqualify us from future bidding opportunities.

Regulation of Sand Proppant Production

The MSHA has primary regulatory jurisdiction over commercial silica operations, including quarries, surface mines, underground mines and industrial mineral processing facilities. MSHA representatives perform at least two annual inspections of our production facilities to ensure employee and general site safety. To date, these inspections have not resulted in any citations for material violations of MSHA standards, and we believe we are in material compliance with MSHA requirements.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although changes to the regulatory burden on the oil and natural gas industry could affect the demand for our services, we would not expect to be affected any differently or to any greater or lesser extent than other companies in the industry with similar operations.

Drilling. Our operations are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The states, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities, including seasonal wildlife closures;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

Federal, state and local regulations provide detailed requirements for the plugging and abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. Although the Corps does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

State Regulation. The states in which we or our customers operate regulate the drilling for, and the production and gathering of, oil and natural gas, including through requirements relating to the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may also regulate rates of production and may establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but they may do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from wells and to limit the number of wells or locations our customers can drill.

The Ohio Department of Natural Resources, or the ODNR, has enacted a comprehensive set of rules to regulate the construction of well pads. Under these new rules, operators must submit detailed horizontal well pad site plans certified by a professional engineer for review by the ODNR Division of Oil and Gas Resources Management prior to the construction of a well pad. These rules have resulted in increased construction costs for operators.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

OSHA Matters

We are also subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and the public. Compliance with these laws and regulations has not had a material adverse effect on our operations or financial position.

Employees

As of December 31, 2017, we had 1,846 full time employees. None of our employees are represented by labor unions or covered by any collective bargaining agreements. We also hire independent contractors and consultants involved in land, technical, regulatory and other disciplines to assist our full time employees.

Availability of Company Reports

Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on the Investor Relations page of our website at www.mammothenergy.com as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. Information contained on our website, or on other websites that may be linked to our website, is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

Item 1A. Risk Factors

Risks Related to Our Business and the Industries We Serve

A portion of our business depends on the oil and natural gas industry and particularly on the level of exploration and production activity within the United States and Canada, and the ongoing volatility in prices for oil and natural gas has had, and continues to have, an adverse effect on our revenue, cash flows, profitability and growth.

Demand for our oil and natural gas products and services depends substantially on the level of expenditures by companies in the oil and natural gas industry. The significant decline in oil and natural gas prices during 2015 continued during the first part of 2016 before seeing a rebound during the second half of 2016 and throughout 2017. The low commodity price environment caused many of our customers to reduce spending on drilling, completion and other production activities. Although the prices for oil and natural gas have recently stabilized, the industry conditions are dynamic and the continuation or a weakening of commodity prices from current levels may result in a material adverse impact on certain of our customers' liquidity and financial position resulting in spending reductions, delays in the collection of amounts owing to us and similar impacts. These conditions have had and may continue to have an adverse impact on our financial condition, results of operations and cash flows, and it is difficult to predict how long the current commodity price environment will continue.

Many factors over which we have no control affect the supply of and demand for, and our customers' willingness to explore, develop and produce oil and natural gas, and therefore, influence prices for our products and services, including:

- the domestic and foreign supply of and demand for oil and natural gas;
- the level of prices, and expectations about future prices, of oil and natural gas;
- the level of global oil and natural gas exploration and production;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the expected decline rates of current production;
- the price and quantity of foreign imports;
- political and economic conditions in oil producing countries, including the Middle East, Africa, South America and Russia;

- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- speculative trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;
- the discovery rates of new oil and natural gas reserves;
- contractions in the credit market;
- the strength or weakness of the U.S. dollar;
- available pipeline and other transportation capacity;
- the levels of oil and natural gas storage;
- weather conditions and other natural disasters;
- political instability in oil and natural gas producing countries;
- domestic and foreign tax policy;
- domestic and foreign governmental approvals and regulatory requirements and conditions;
- the continued threat of terrorism and the impact of military and other action, including military action in the Middle East;
- technical advances affecting energy consumption;
- the proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of alternative fuels;
- the ability of oil and natural gas producers to raise equity capital and debt financing;
- merger and divestiture activity among oil and natural gas producers; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. Any of the above factors could impact the level of oil and natural gas exploration and production activity and could ultimately have a material adverse effect on our business, financial condition, results of operations and cash flows. Further, future weakness in commodity prices could impact our business going forward, and we could encounter difficulties such as an inability to access needed capital on attractive terms or at all, recognizing asset impairment charges, an inability to meet financial ratios contained in our debt agreements, a need to reduce our capital spending and other similar impacts.

The cyclicality of the oil and natural gas industry may cause our operating results to fluctuate.

We derive a portion of our revenues from companies in the oil and natural gas exploration and production industry, a historically cyclical industry with levels of activity that are significantly affected by the levels and volatility of oil and natural gas prices. We have, and may in the future, experience significant fluctuations in operating results as a result of the reactions of our customers to changes in oil and natural gas prices. For example, prolonged low commodity prices experienced by the oil and natural gas industry during 2015 and the first part of 2016, combined with adverse changes in the capital and credit markets, caused many exploration and production companies to reduce their capital budgets and drilling activity. This resulted in a significant decline in demand for oilfield services and adversely impacted the prices oilfield services companies could charge for their services. In addition, a majority of the service revenue we earn is based upon a charge for a relatively short period of time (e.g., an hour, a day, a week) for the actual period of time the service is provided to our customers. By contracting services on a short-term basis, we are exposed to the risks of a rapid reduction in market prices and utilization, with resulting volatility in our revenues.

If oil prices or natural gas prices decline, the demand for our oil and natural gas services could be adversely affected.

The demand for our oil and natural gas services is primarily determined by current and anticipated oil and natural gas prices and the related general production spending and level of drilling activity in the areas in which we have operations. Volatility or weakness in oil prices or natural gas prices (or the perception that oil prices or natural gas prices will decrease) affects the spending patterns of our customers and may result in the drilling of fewer new wells or lower production spending on existing wells. This, in turn, could result in lower demand for our services and may cause lower rates and lower utilization of our well service equipment.

Any future decline in oil and gas prices could materially affect the demand for our services and our results of operations could be materially and adversely affected. Prices for oil and natural gas historically have been extremely volatile and are expected to continue to be volatile in the years to come. During 2017, West Texas Intermediate posted prices ranged from $42.53 to $60.42 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.56 to $3.72 per MMBtu. If the prices of oil and natural gas decline from current levels, our operations, financial condition and level of expenditures may be materially and adversely affected.

Our business is difficult to evaluate because we have a limited operating history.

Mammoth Energy Services, Inc. was formed in June 2016, and did not conduct any material business operations prior to its initial public offering, or the IPO, which closed on October 19, 2016. Prior to the IPO, Mammoth Energy Services, Inc. was a wholly-owned subsidiary of Mammoth Energy Partners LP, referred to as Mammoth Partners, which was originally formed in February 2014. Except as expressly noted otherwise, the historical financial information of Mammoth Energy Services, Inc. and operational data for the periods prior to October 12, 2016 is that of Mammoth Partners and its consolidated subsidiaries. These subsidiaries were formed or acquired between 2007 and 2016. As a result, there is only limited historical financial and operating information available upon which to base your evaluation of our performance.

Our customer base is concentrated and the loss of one or more of our significant customers, or their failure to pay the amounts they owe us, could cause our revenue to decline substantially.

Our top five customers accounted for approximately 71% and 80%, respectively, of our revenue for the years ended December 31, 2017 and 2016. Gulfport was our largest customer for the years ended December 31, 2017 and 2016 accounting for approximately 30% and 57%, respectively, of our revenue. PREPA was our second largest customer for the year ended December 31, 2017 accounting for approximately 29% of our revenue. It is likely that we will continue to derive a significant portion of our revenue from a relatively small number of customers in the future. If a major customer decided not to continue to use our services, our revenue would decline and our operating results and financial condition could be harmed. In addition, we are subject to credit risk due to the concentration of our customer base. Any nonperformance by our counterparties, including their failure to pay the amounts they owe us on a timely basis or at all, either as a result of changes in financial and economic conditions or otherwise, could have an adverse impact on our operating results and could adversely affect our liquidity.

Our failure to receive payment for contract change orders or adequately recover on claims brought by us against customers related to payment terms and costs could materially and adversely affect our financial position, results of operations and cash flows.

We have in the past brought, and may in the future bring, claims against our customers related to, among other things, the payment terms of our contracts and change orders relating to such contracts. These types of claims can occur due to, among other things, customer-caused delays or changes in project scope, both of which may result in additional costs. In some instances, these claims can be the subject of lengthy legal proceedings, and it is difficult to predict the timing and outcome of such proceedings. Our failure to promptly and adequately recover on these types of claims could have an adverse impact on our financial condition, results of operations and cash flows.

One of our infrastructure services subsidiaries recently entered into a contract with PREPA, which, as amended, provides for payments to us of up to $945.4 million. PREPA is currently subject to pending bankruptcy proceedings. In the event that PREPA does not have or does not obtain the funds necessary to satisfy its payment obligations to our subsidiary under the contract or terminates the contract prior to the end of the contract term, our financial condition, results of operations and cash flows could be materially and adversely affected.

On October 19, 2017, one of our subsidiaries, Cobra, and PREPA entered into an emergency master services agreement for repairs to PREPA's electrical grid as a result of Hurricane Maria. The one-year contract, as amended through February 27, 2018, provides for payments of up to $945.4 million. PREPA is currently subject to bankruptcy proceedings pending in the U.S. District Court for the District of Puerto Rico. As a result, PREPA's ability to meet its payment obligations under the contract will be largely dependent upon funding from the Federal Emergency Management Agency, or FEMA, or other sources. PREPA's contracting practices in connection with restoration and repair of PREPA's electrical grid in Puerto Rico, and the terms of certain of those contracts, have been subject to critical comment and are the subject of review and hearings by U.S. federal and Puerto Rican governmental entities. Recently, a contract for restoration and repair services entered into by PREPA with an unrelated third party was terminated by PREPA. In the event that PREPA does not have or does not obtain the funds necessary to satisfy its current obligations to Cobra under the contract or terminates the contract prior to the end of the contract term, our financial condition, results of operations and cash flows could be materially and adversely affected. In addition, government contracts are subject to various uncertainties, restrictions and regulations, including oversight audits by government representatives and profit and cost controls, which could result in withholding or delayed payments to us or efforts to recover payments already made.

We provide the majority of our hydraulic fracturing completion services to a limited number of customers, and the termination of one or more of these relationships could adversely affect our operations.

We provide completion services, which services include hydraulic fracturing. The majority of our revenue from this business is derived from Gulfport pursuant to a contract that expires in September 2018. We cannot assure you that we will be able to extend or renew our contract with Gulfport on favorable terms and conditions or at all. Likewise, we cannot assure you that we would be able to obtain a replacement long-term contract with other customers sufficient to continue providing the level of services as we currently do with Gulfport. The termination of our relationship or nonrenewal of our contract with Gulfport, or one or more of our other customers, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We provide the majority of our infrastructure services to one customer, and the termination of this relationship could adversely affect our operations.

We provide infrastructure services that focus on the repair, maintenance and construction of transmission and distribution networks. The majority of our revenue from this business has been derived from PREPA pursuant to a contract entered into on October 19, 2017, as subsequently amended, with a term of up to one year. We cannot assure you that we will be able to continue our contract with PREPA on favorable terms and conditions or at all. Likewise, we cannot assure you that we will be able to obtain one or more replacement contracts with other customers sufficient to continue providing the level of services as we currently do with PREPA. The termination of our relationship with PREPA could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We provide natural sand proppant to a limited number of customers, and the termination of one or more of these relationships could adversely affect our operations.

We provide natural sand proppant used for hydraulic fracturing. Historically, we have derived a large portion of our revenue from this business from Gulfport pursuant to a contract that expires in September 2018. The termination of our relationship or nonrenewal of our contract with Gulfport, or one or more of our other customers, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Deterioration of the commodity price environment can negatively impact oil and natural gas exploration and production companies and, in some cases, impair their ability to timely pay for products or services provided or result in their insolvency or bankruptcy, any of which exposes us to credit risk of our oil and natural gas exploration and production customers.

In weak economic and commodity price environments, we may experience increased difficulties, delays or failures in collecting outstanding receivables from our customers, due to, among other reasons, a reduction in their cash flow from operations, their inability to access the credit markets and, in certain cases, their insolvencies. Such increases in collection issues could have a material adverse effect on our business, results of operations, cash flows and financial condition. We cannot assure you that the reserves we have established for potential credit losses will be sufficient to meet write-offs of uncollectible receivables or that our losses from such receivables will be consistent with our expectations. To the extent one or more of our key customers commences bankruptcy proceedings, our contracts with these customers may be subject to rejection under applicable provisions of the United States Bankruptcy Code, or may be renegotiated. Further, during any such bankruptcy proceeding, prior to assumption, rejection or renegotiation of such contracts, the bankruptcy court may temporarily authorize the payment of value for our services less than contractually required, which could also have a material adverse effect on our business, results of operations, cash flows and financial condition.

Delays and reductions in government appropriations can negatively impact energy infrastructure construction, maintenance and repair projects and may impair the ability of our energy infrastructure customers to timely pay for products or services provided or result in their insolvency or bankruptcy, any of which exposes us to credit risk of our infrastructure customers.

Many of our infrastructure customers derive funding from federal, state and local bodies. Delayed or reduced appropriations may cancel, curtail or delay projects and may have an adverse effect on our business, results of operations, cash flows and financial condition.

Competition within the energy services industry may adversely affect our ability to market our services.

The energy services industry is highly competitive and fragmented and includes numerous small companies capable of competing effectively in our markets on a local basis, as well as large companies that possess substantially greater financial and other resources than we do. Our larger competitors' greater resources could allow those competitors to compete more effectively than we can. The amount of equipment available may exceed demand, which could result in active price competition. Many contracts are awarded on a bid basis, which may further increase competition based primarily on price. In addition, adverse market conditions lower demand for well servicing equipment, which results in excess equipment and lower utilization rates. If market conditions in our oil-oriented operating areas were to deteriorate or if adverse market conditions in our natural gas-oriented operating areas persist, utilization rates may decline.

Shortages, delays in delivery and interruptions in supply of drill pipe, replacement parts, other equipment, supplies and materials may adversely affect our contract land and directional drilling business or our pressure pumping business.

During periods of increased demand for drilling and completion 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, replacement parts, other equipment, 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; and
- 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.

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 or pressure pumping fleets and could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Oilfield services equipment, refurbishment and new asset construction projects, as well as the reactivation of oilfield service assets that have been idle for six months or longer, are subject to risks which could cause delays or cost overruns and adversely affect our business, cash flows, results of operations and financial position.

Oilfield services equipment or assets being upgraded, converted or re-activated following a period of inactivity may experience start-up complications and may encounter other operational problems that could result in significant delays, uncompensated downtime, reduced dayrates or the cancellation, termination or non-renewal of contracts. Construction and upgrade projects are subject to risks of delay or significant cost overruns inherent in any large construction project from numerous factors, including the following:

- shortages of equipment, materials or skilled labor;
- unscheduled delays in the delivery of ordered materials and equipment or shipyard construction;
- failure of equipment to meet quality and/or performance standards;
- financial or operating difficulties of equipment vendors;
- unanticipated actual or purported change orders;
- inability by us or our customers to obtain required permits or approvals, or to meet applicable regulatory standards in our areas of operations;
- unanticipated cost increases between order and delivery;
- adverse weather conditions and other events of force majeure;
- design or engineering changes; and
- work stoppages and other labor disputes.

The occurrence of any of these events could have a material adverse effect on our business, cash flows, results of operations and financial position.

Advancements in oilfield service technologies could have a material adverse effect on our business, financial condition, results of operations and cash flows.

The oilfield services industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As new horizontal and directional drilling, pressure pumping, pressure control and well service technologies develop, we may be placed at a competitive disadvantage, and competitive pressure may force us to implement new technologies at a substantial cost. We may not be able to successfully acquire or use new technologies. Further, our customers are increasingly demanding the services of newer, higher specification drilling rigs. There can be no assurance that we will:

- have sufficient capital resources to build new, technologically advanced equipment and other assets;
- successfully integrate additional oilfield service equipment and other assets;
- effectively manage the growth and increased size of our organization, equipment and other assets;
- successfully deploy idle, stacked or additional oilfield service assets;
- maintain crews necessary to operate additional drilling rigs or pressure pumping service equipment; or
- successfully improve our financial condition, results of operations, business or prospects.

If we are not successful in building or acquiring new oilfield service equipment and other assets or upgrading our existing rigs and equipment in a timely and cost-effective manner, we could lose market share. New technologies, services or standards could render some of our services, equipment and other assets obsolete, which could have a material adverse impact on our business, cash flows, results of operations and financial condition.

Our business depends upon our ability to obtain specialized equipment and parts from third-party suppliers, and we may be vulnerable to delayed deliveries and future price increases.

We purchase specialized equipment and parts from third party suppliers. At times during the business cycle, there is a high demand for hydraulic fracturing, coiled tubing and other oilfield services and extended lead times to obtain equipment needed to provide these services. Further, there are a limited number of suppliers that manufacture the equipment we use. Should our current suppliers be unable or unwilling to provide the necessary equipment and parts or otherwise fail to deliver the products timely and in the quantities required, any resulting delays in the provision of our services could have a material adverse effect on our business, financial condition, results of operations and cash flows. In addition, future price increases for this type of equipment and parts could negatively impact our ability to purchase new equipment to update or expand our existing fleet or to timely repair equipment in our existing fleet.

An increase in the prices of certain materials used in our businesses could adversely affect our business, financial condition, results of operation and cash flows.

We are exposed to market risk of increases in certain commodity prices of materials, such as copper and steel, which are used as components of supplies or materials utilized in some of our infrastructure and pressure pumping businesses. An increase in these materials could increase our operating costs, limit our ability to service our customers' needs or otherwise materially and adversely affect our business, financial condition, results of operation and cash flows.

Inaccuracies in estimates of volumes and qualities of our sand reserves could result in lower than expected sales and higher than expected production costs.

On May 26, 2017, we acquired substantially all of the assets of Chieftain Sand and Proppant, LLC and Chieftain Sand and Proppant Barron, LLC, unrelated third party sellers, following our successful bid in a bankruptcy court auction, which assets include a wet and dry plant and sand mine located on approximately 608 acres in New Auburn, Wisconsin. Also, on June 5, 2017, we acquired from Gulfport, certain affiliates of Wexford Capital LP, which we refer to as Wexford, and Rhino Exploration LLC, which we refer to as Rhino, all outstanding membership interests in Sturgeon Acquisitions LLC, which owns Taylor Frac, LLC, Taylor Real Estate Investments, LLC and South River Road, LLC (collectively referred to as Taylor Frac). These acquisitions added sand reserves to our operations and increased our production capacity.

Estimates of our sand reserves are by nature imprecise and depend to some extent on statistical inferences drawn from available data, which may prove unreliable. There are numerous uncertainties inherent in estimating quantities and qualities of sand reserves and costs to mine recoverable reserves, including many factors beyond our control. Estimates of economically recoverable sand reserves necessarily depend on a number of factors and assumptions, all of which may vary considerably from actual results, such as:

- geological and mining conditions and/or effects from prior mining that may not be fully identified by available data or that may differ from experience;
- assumptions concerning future prices of frac sand, operating costs, mining technology improvements, development costs and reclamation costs; and
- assumptions concerning future effects of regulation, including the issuance of required permits and taxes by governmental agencies.

Any inaccuracy in the estimates related to our sand reserves could result in lower than expected sales and higher than expected costs. For example, these estimates assume that our revenue and cost structure will remain relatively constant over the life of our reserves. If these assumptions prove to be inaccurate, some or all of our reserves may not be economically mineable, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. In addition, our current customer contracts require us to deliver frac sand that meets certain specifications. If the estimates of the quality of our sand reserves, including the volumes of the various specifications of those reserves, prove to be inaccurate, we may incur significantly higher excavation costs without corresponding increases in revenues, we may not be able to meet our contractual obligations, or our facilities may have a shorter than expected reserve life, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

As part of our natural sand proppant services business, we rely on third parties for raw materials and transportation, and the suspension or termination of our relationship with one or more of these third parties could adversely affect our business, financial conditions, results of operations and cash flows.

As part of our natural sand proppant services business, we mine and process sand into premium monocrystalline sand, a specialized mineral that is used as a proppant (also known as frac sand) at our Barron County and Jackson County, Wisconsin plants. We also buy processed sand from suppliers on the spot market. In addition, we also buy raw or washed sand and process it at our indoor sand processing plant located in Pierce County, Wisconsin. We sell natural sand proppant to our customers for use in their hydraulic fracturing operations to enhance the recovery rates of hydrocarbons from oil and natural gas wells. We also provide logistics solutions to deliver our frac sand products to our customers. Because our customers generally find it impractical to store frac sand in large quantities near their job sites, they seek to arrange for product to be delivered where and as needed, which requires predictable and efficient loading and shipping of product. To facilitate our logistics and transload facility capabilities, we contract with third party providers to transport our frac sand products to railroad facilities for delivery to our customers. We also lease a railcar fleet from various third parties to deliver our frac sand products to our customers and lease or otherwise utilize origin and destination transloading facilities. The suspension, termination or nonrenewal of our relationship with any one or more of these third parties involved in the sourcing, transportation and delivery of our frac sand products could result in material operational delays, increase our operating costs, limit our ability to service our customers' wells or otherwise materially and adversely affect our business, financial condition, results of operations and cash flows.

Future performance of our natural sand proppant services business will depend on our ability to succeed in competitive markets, and on our ability to appropriately react to potential fluctuations in the demand for and supply of frac sand.

In our natural sand proppant services business, we operate in a highly competitive market that is characterized by a small number of large, national producers and a larger number of small, regional or local producers. Competition in the industry is based on price, consistency and quality of product, site location, distribution and logistics capabilities, customer service, reliability of supply and breadth of product offering. The large, national producers with whom we compete include Badger Mining Corporation, Fairmount Santrol Holdings, Inc., Hi-Crush Partners LP, Preferred Proppants LLC, Unimin Corporation, Smart Sand, Inc., Emerge Energy Services LP and U.S. Silica Holdings Inc. Our larger competitors may have greater financial and other resources than we do, may develop technology superior to ours, may have production facilities that are located closer to sand mines from which raw sand is mined or to their key customers than our facilities or have a more cost effective access to raw sand and transportation facilities than we do. Should the demand for hydraulic fracturing services decrease, prices in the frac sand market could materially decrease as producers may seek to preserve market share or exit the market and sell frac sand at below market prices. In addition, oil and natural gas exploration and production companies and other providers of hydraulic fracturing services could acquire their own frac sand reserves, develop or expand frac sand production capacity or otherwise fulfill their own proppant requirements and existing or new frac sand producers could add to or expand their frac sand production capacity, which may negatively impact pricing and demand for our frac sand. We may not be able to compete successfully against either our larger or smaller competitors in the future, and competition could have a material adverse effect on our business, financial condition, results of operations and cash flows.

An increase in the supply of raw frac sand having similar characteristics as the raw frac sand we produce and sell could make it more difficult for us to market our sand on favorable terms or at all.

From time to time we have entered into take-or-pay contracts with our principal raw frac sand supplier for our Pierce County, Wisconsin plant. If significant new reserves of raw frac sand continue to be discovered and developed, and those frac sands have similar characteristics to the frac sand we produce and sell, the market price for our frac sand may decline. If the market price for our frac sand falls below an amount equal to the contracted purchase price in our take-or-pay contract plus our processing and related transportation costs, this could have an adverse effect on our business, financial condition, results of operations and cash flows over the remaining term of this contract.

Diminished access to water and inability to secure or maintain necessary permits may adversely affect operations of our frac sand processing plants.

The processing of raw sand and production of natural sand proppant require significant amounts of water. As a result, securing water rights and water access is necessary to operate our processing facilities. If the areas where our facilities are located experience water shortages, restrictions or any other constraints due to drought, contamination or otherwise, there may be additional costs associated with securing water access. Although we have obtained water rights to service our activities when we are operating our processing plants, the amount of water that we are entitled to use pursuant to our water rights must be determined by the appropriate regulatory authorities. Such regulatory authorities may amend the regulations regarding such water rights, increase the cost of maintaining such water rights or eliminate our current water rights, and we may be unable to retain all or a portion of such water rights. If implemented, these new regulations could also affect local municipalities and other industrial operations and could have a material adverse effect on costs involved in operating our processing plant. Such changes in laws, regulations or government policy and related interpretations pertaining to water rights may alter the environment in which we do business, which may have an adverse effect on our business, financial condition, results of operations and cash flows. Additionally, a water discharge permit may be required to properly dispose of water at our processing sites when in operation. Certain of our facilities are also required to obtain storm water permits. The water discharge, storm water or any other permits we may be required to have in order to conduct our frac sand processing operations is subject to regulatory discretion, and any inability to obtain or maintain the necessary permits could have an adverse effect on our ability to run such operations.

Demand for our frac sand products could be reduced by changes in well stimulation processes and technologies, as well as changes in governmental regulations and other applicable law.

As part of our natural sand proppant services business, we mine, process and sell frac sand products to our customers for use in their hydraulic fracturing operations to enhance the recovery rates of hydrocarbons from oil and natural gas wells. A significant shift in demand from frac sand to other proppants, or the development of new processes to replace hydraulic fracturing altogether, could cause a decline in the demand for the frac sand we produce and result in a material adverse effect on our business, financial condition, results of operations and cash flows. Further, federal and state governments and agencies have adopted various laws and regulations or are evaluating proposed legislation and regulations that are focused on the extraction of shale gas or oil using hydraulic fracturing, a process which utilizes proppants such as those that we produce. Future hydraulic fracturing-related legislation or regulations could restrict the ability of our customers to utilize, or increase the cost associated with, hydraulic fracturing, which could reduce demand for our proppants and adversely affect our business, financial condition, results of operations and cash flows. For additional information regarding the regulation of hydraulic fracturing, see " *—Risks Related to Our Business and the Oil and Natural Gas Industry—Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays*."

The customized nature, and remote location, of the modular camps that we provide and service present unique challenges that could adversely affect our ability to successfully operate our remote accommodations business.

We rely on a third-party subcontractor to manufacture and install the customized modular units used in our remote accommodations business. These customized units often take a considerable amount of time to manufacture and, once manufactured, often need to be delivered to remote areas that are frequently difficult to access by traditional means of transportation. In the event we are unable to provide these modular units in a timely fashion, we may not be entitled to full, or any, payment therefor under the terms of our contracts with customers. In addition, the remote location of the modular camps often makes it difficult to install and maintain the units, and our failure, on a timely basis, to have such units installed and provide maintenance services could result in our breach of, and non-payment by our customers under, the terms of our customer contracts. Any of these factors could have a material adverse effect on our remote accommodation business and our overall financial condition and results of operations.

Health and food safety issues and food-borne illness concerns could adversely affect our remote accommodations business.

We provide food services to our customers as part of our remote accommodations business and, as a result, face health and food safety issues that are common in the food and hospitality industries. Food-borne illnesses, such as E. coli, hepatitis A, trichinosis or salmonella, and food safety issues have occurred in the food industry in the past and could occur in the future. Our reliance on third-party food suppliers and distributors increases the risk that food-borne illness incidents could be caused by factors outside of our control. New illnesses resistant to any precautions may develop in the future, or diseases with long incubation periods could arise. Further, the remote nature of our accommodation facilities and related food services may increase the risk of contamination of our food supply and create additional health and hygiene concerns due to the limited access to modern amenities and conveniences that may not be faced by other food service providers or hospitality businesses operating in an urban environment. If our customers become ill from food-borne illness, we could be forced to close some or all of our remote accommodation facilities on a temporary basis or otherwise. Any such incidents and/or any report of publicity linking us to incidents of food-borne illness or other food safety issues, including food tampering or contamination, could adversely affect our remote accommodations business as well as our overall financial condition and results of operations.

Development of permanent infrastructure in the Canadian oil sands region or other locations where we locate our remote accommodations could negatively impact our remote accommodations business.

Our remote accommodations business specializes in providing modular housing and related services for work forces in remote areas which lack the infrastructure typically available in towns and cities. If permanent towns, cities and municipal infrastructure develop in the oil sands region of northern Alberta, Canada or other regions where we locate our modular camps, then demand for our accommodations could decrease as customer employees move to the region and choose to utilize permanent housing and food services.

Revenue generated and expenses incurred by our remote accommodation business are denominated in the Canadian dollar and could be negatively impacted by currency fluctuations.

Our remote accommodation business generates revenue and incurs expenses that are denominated in the Canadian dollar. These transactions could be materially affected by currency fluctuations. Changes in currency exchange rates could adversely affect our combined results of operations or financial position. We also maintain cash balances denominated in the Canadian dollar. At December 31, 2017, we had \$2.5 million of cash in Canadian dollars, in Canadian accounts. A 10% increase in the strength of the Canadian dollar versus the U.S. dollar would have resulted in an increase in pre-tax income of approximately \$0.1 million as of December 31, 2017. Conversely, a corresponding decrease in the strength of the Canadian dollar would have resulted in a comparable decrease in pre-tax income. We have not hedged our exposure to changes in foreign currency exchange rates and, as a result, could incur unanticipated translation gains and losses.

Certain of our completion and production services, particularly our hydraulic fracturing services, are substantially dependent on the availability of water. Restrictions on our ability, or our customers' ability, to obtain water may have an adverse effect on our business, financial condition, results of operations and cash flows.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Over the past several years, certain of the areas have experienced extreme drought conditions and competition for water in such shales is growing. As a result of this severe drought, some local water districts have begun restricting the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supply. Our inability, or customers' inability, to obtain water to use in our operations from local sources or to effectively utilize flowback water could have an adverse effect on our business, financial condition, results of operations and cash flows.

We rely on a few key employees whose absence or loss could adversely affect our business.

Many key responsibilities within our business have been assigned to a small number of employees. The loss of their services could adversely affect our business. In particular, the loss of the services of our Chief Executive Officer or Chief Financial Officer could disrupt our operations. We do not have any written employment agreement with our executives at this time. Further, we do not maintain "key person" life insurance policies on any of our employees. As a result, we are not insured against any losses resulting from the death of our key employees.

If we are unable to employ a sufficient number of skilled and qualified workers, our capacity and profitability could be diminished and our growth potential could be impaired.

The delivery of our products and services requires skilled and qualified workers with specialized skills and experience who can perform physically demanding work. As a result of the volatility of the energy services industry and the demanding nature of the work, workers may choose to pursue employment in fields that offer a more desirable work environment at wage rates that are competitive. Our ability to be productive and profitable will depend upon our ability to employ and retain skilled workers. In addition, our ability to expand our operations depends in part on our ability to increase the size of our skilled labor force. The demand for skilled workers is high, and the supply is limited. As a result, competition for experienced energy service personnel is intense, and we face significant challenges in competing for crews and management with large and well established competitors. A significant increase in the wages paid by competing employers could result in a reduction of our skilled labor force, increases in the wage rates that we must pay, or both. If either of these events were to occur, our capacity and profitability could be diminished and our growth potential could be impaired.

Unionization efforts could increase our costs or limit our flexibility.

Presently, none of our employees work under collective bargaining agreements. Unionization efforts have been made from time to time within our industries, to varying degrees of success. Any such unionization could increase our costs or limit our flexibility.

Our operations may be limited or disrupted in certain parts of the continental U.S., Puerto Rico and Canada during severe weather conditions, which could have a material adverse effect on our financial condition and results of operations.

We provide pressure pumping and well services and contract land and directional drilling services in the Utica, SCOOP, STACK, Permian Basin, Marcellus, Granite Wash, Cana Woodford and Eagle Ford resource plays located in the continental U.S. We provide infrastructure services in the northeast, southwest and midwest portions of the United States and Puerto Rico. We provide remote accommodation services in the oil sands in Alberta, Canada. We serve these markets through our facilities and service centers located in Ohio, Oklahoma, Texas, Wisconsin, Minnesota, Kentucky, Puerto Rico and Alberta, Canada. For the years ended December 31, 2017 and 2016, we generated approximately 42% and 84%, respectively, of our revenue from our operations in Ohio, Wisconsin, Minnesota, North Dakota, Pennsylvania, West Virginia and Canada where weather conditions may be severe, particularly during winter and spring months. Repercussions of severe weather conditions may include:

- curtailment of services;
- weather-related damage to equipment resulting in suspension of operations;
- weather-related damage to our facilities;
- inability to deliver equipment and materials to jobsites in accordance with contract schedules; and
- loss of productivity.

Many municipalities, including those in Ohio and Wisconsin, impose bans or other restrictions on the use of roads and highways, which include weight restrictions on the paved roads that lead to our jobsites due to the muddy conditions caused by spring thaws. This can limit our access to these jobsites and our ability to service wells in these areas. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs in those regions. Weather conditions may also affect the price of crude oil and natural gas, and related demand for our services. Any of these factors could have a material adverse effect on our financial condition and results of operations.

Concerns over general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit and the European, Asian and the United States financial markets have contributed to economic uncertainty and diminished expectations for the global economy. These factors, combined with volatility in commodity prices, business and consumer confidence and unemployment rates, have in the past precipitated and may in the future precipitate an economic slowdown. Concerns about global economic growth may have a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which oil, natural gas and natural gas liquids can be sold, which could affect the ability of our customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

A terrorist attack or armed conflict could harm our business.

The occurrence or threat of terrorist attacks in the United States or other countries, anti-terrorist efforts and other armed conflicts involving the United States or other countries, including continued hostilities in the Middle East, may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Our operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could limit our ability to grow.

Our capital budget for 2018 is estimated to be $125 million. Since November 2014, we have funded our capital expenditures primarily with cash on hand, cash proceeds from our initial public offering, cash generated by operations and borrowings under our revolving credit facility (other than our acquisitions in June 2017, which we completed with the issuance of shares of our common stock). We may be unable to generate sufficient cash from operations and other capital resources to maintain planned or future levels of capital expenditures which, among other things, may prevent us from acquiring new equipment or properly maintaining our existing equipment. Further, any disruptions or continuing volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. This could put us at a competitive disadvantage or interfere with our growth plans. Further, our actual capital expenditures for 2018 or future years could exceed our capital expenditure budget. In the event our capital expenditure requirements at any time are greater than the amount we have available, we could be required to seek additional sources of capital, which may include debt financing, joint venture partnerships, sales of assets, offerings of debt or equity securities or other means. We may not be able to obtain any such alternative source of capital. We may be required to curtail or eliminate contemplated activities. If we can obtain alternative sources of capital, the terms of such alternative may not be favorable to us. In particular, the terms of any debt financing may include covenants that significantly restrict our operations. Our inability to grow as planned may reduce our chances of maintaining and improving profitability.

The growth of our business through acquisitions may expose us to various risks, including those relating to difficulties in identifying suitable, accretive acquisition opportunities and integrating businesses, assets and personnel, as well as difficulties in obtaining financing for targeted acquisitions and the potential for increased leverage or debt service requirements.

As a component of our business strategy, we have pursued and intend to continue to pursue selected, accretive acquisitions of complementary assets, businesses and technologies. Acquisitions involve numerous risks, including:

- unanticipated costs and assumption of liabilities and exposure to unforeseen liabilities of acquired businesses, including but not limited to environmental liabilities;
- difficulties in integrating the operations and assets of the acquired business and the acquired personnel;
- limitations on our ability to properly assess and maintain an effective internal control environment over an acquired business, in order to comply with public reporting requirements;
- potential losses of key employees and customers of the acquired businesses;
- inability to commercially develop acquired technologies;
- risks of entering markets in which we have limited prior experience; and
- increases in our expenses and working capital requirements.

The process of integrating an acquired business may involve unforeseen costs and delays or other operational, technical and financial difficulties and may require a disproportionate amount of management attention and financial and other resources. Our failure to achieve consolidation savings, to incorporate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations. Furthermore, there is intense competition for acquisition opportunities in our industries. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. In addition, we may not have sufficient capital resources to complete additional acquisitions. Historically, we have financed capital expenditures primarily with funding from our initial public offering, cash generated by operations, borrowings under our revolving credit facility and funding from our equity investors. We may incur substantial indebtedness to finance future acquisitions and also may issue equity, debt or convertible securities in connection with such acquisitions. 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 our existing stockholders. Furthermore, we may not be able to obtain additional financing on satisfactory terms. Even if we have access to the necessary capital, we may be unable to continue to identify additional suitable acquisition opportunities, negotiate acceptable terms or successfully acquire identified targets. Our ability to grow through acquisitions and manage growth will require us to continue to invest in operational, financial and management information systems and to attract, retain, motivate and effectively manage our employees. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

We may have difficulty managing growth in our business, which could adversely affect our financial condition and results of operations.

As a recently formed company, growth in accordance with our business plan, if achieved, could place a significant strain on our financial, technical, operational and management resources. As we expand the scope of our activities and our geographic coverage through both organic growth and acquisitions, there will be additional demands on our financial, technical, operational and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrences of unexpected expansion difficulties, including the failure to recruit and retain experienced managers, engineers and other professionals in the energy services industry, could have a material adverse effect on our business, financial condition, results of operations and our ability to successfully or timely execute our business plan.

If our intended expansion of our business is not successful, our financial condition, profitability and results of operations could be adversely affected, and we may not achieve increases in revenue and profitability that we hope to realize.

A key element of our business strategy involves the expansion of our services, geographic presence and customer base. These aspects of our strategy are subject to numerous risks and uncertainties, including:

- an inability to retain or hire experienced crews and other personnel;
- a lack of customer demand for the services we intend to provide;
- an inability to secure necessary equipment, raw materials (particularly sand and other proppants) or technology to successfully execute our expansion plans;
- shortages of water used in our sand processing operations and our hydraulic fracturing operations;
- unanticipated delays that could limit or defer the provision of services by us and jeopardize our relationships with existing customers and adversely affect our ability to obtain new customers for such services; and
- competition from new and existing services providers.

Encountering any of these or any unforeseen problems in implementing our planned expansion could have a material adverse impact on our business, financial condition, results of operations and cash flows, and could prevent us from achieving the increases in revenues and profitability that we hope to realize.

Our liquidity needs could restrict our operations and make us more vulnerable to adverse economic conditions.

Our future indebtedness, whether incurred in connection with acquisitions, operations or otherwise, may adversely affect our operations and limit our growth, and we may have difficulty making debt service payments on such indebtedness as payments become due. Our level of indebtedness may affect our operations in several ways, including the following:

- increasing our vulnerability to general adverse economic and industry conditions;
- the covenants that are contained in the agreements governing our indebtedness could limit our ability to borrow funds, dispose of assets, pay dividends and make certain investments;
- our debt covenants could also affect our flexibility in planning for, and reacting to, changes in the economy and in our industries;
- any failure to comply with the financial or other covenants of our debt, including covenants that impose requirements to maintain certain financial ratios, could result in an event of default, which could result in some or all of our indebtedness becoming immediately due and payable;
- our level of debt could impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or other general corporate purposes; and
- our business may not generate sufficient cash flow from operations to enable us to meet our obligations under our indebtedness.

Our revolving credit facility imposes, and any of our future credit facilities may impose, restrictions on us that may affect our ability to successfully operate our business.

Our revolving credit facility limits, and any of our future credit facilities may limit, our ability to take various actions, such as:

- incurring additional indebtedness;
- paying dividends;
- creating certain additional liens on our assets;
- entering into sale and leaseback transactions;
- making investments;
- entering into transactions with affiliates;
- making material changes to the type of business we conduct or our business structure;
- making guarantees;
- entering into hedges;
- disposing of assets in excess of certain permitted amounts;
- merging or consolidating with other entities; and
- selling all or substantially all of our assets.

In addition, our revolving credit facility requires, and any future debt may require, us to maintain certain financial ratios and to satisfy certain financial conditions, which may require us to reduce our debt or take some other action in order to comply with each of them. These restrictions could also limit our ability to obtain future financings, make needed capital expenditures, withstand a downturn in our business or the economy in general, or otherwise conduct necessary corporate activities. We also may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under our revolving credit facility and any future debt agreements. If we fail to comply with the covenants in our existing revolving credit facility or any future debt agreements and such failure is not waived by the lender, a default may be declared by the lenders, which could have a material adverse effect on us.

Our revolving credit facility provides, and any future credit facilities may provide, for variable interest rates, which may increase or decrease our interest expense.

At December 31, 2017, we had $99.9 million outstanding under our revolving credit facility bearing a weighted average interest rate of 4.37%. At December 31, 2017, availability under our credit facility was $62.8 million, after giving effect to $6.5 million of outstanding letters of credit. A 1% increase or decrease in the interest rate at that time would have increased or decreased our interest expense by approximately $1.0 million per year. We do not currently hedge our interest rate exposure.

We may not be able to provide services that meet the specific needs of oil and natural gas exploration and production companies or utilities at competitive prices.

The markets in which we operate are generally highly competitive and have relatively few barriers to entry. The principal competitive factors in our markets are price, product and service quality and availability, responsiveness, experience, technology, equipment quality and reputation for safety. We compete with large national and multi-national companies that have longer operating histories, greater financial, technical and other resources and greater name recognition than we do. Several of our competitors provide a broader array of services and have a stronger presence in more geographic markets. In addition, we compete with several smaller companies capable of competing effectively on a regional or local basis. Our competitors may be able to respond more quickly to new or emerging technologies and services and changes in customer requirements. Some contracts are awarded on a bid basis, which further increases competition based on price. Pricing is often the primary factor in determining which qualified contractor is awarded a job. The competitive environment may be further intensified by mergers and acquisitions among oil and natural gas or utility companies or other events that have the effect of reducing the number of available customers. As a result of competition, we may lose market share or be unable to maintain or increase prices for our present services or to acquire additional business opportunities, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

In addition, some exploration and production companies have begun performing hydraulic fracturing and directional drilling on their wells using their own equipment and personnel. Any increase in the development and utilization of in-house fracturing and directional drilling capabilities by our customers could decrease the demand for our oil and natural gas services and have a material adverse impact on our business.

Our operations are subject to hazards inherent in the oil and natural gas and energy infrastructure industries, which could expose us to substantial liability and cause us to lose customers and substantial revenue.

Our operations include hazards inherent in the oil and natural gas and energy infrastructure industries, such as equipment defects, vehicle accidents, fires, explosions, blowouts, surface cratering, uncontrollable flows of gas or well fluids, pipe or pipeline failures, abnormally pressured formations and various environmental hazards such as oil spills and releases of, and exposure to, hazardous substances. For example, our operations are subject to risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigations and penalties, suspension of operations and repairs required to resume operations. The cost of managing such risks may be significant. The frequency and severity of such incidents will affect operating costs, insurability and relationships with customers, employees and regulators. In particular, our customers may elect not to purchase our services if they view our environmental or safety record as unacceptable, which could cause us to lose customers and substantial revenues. In addition, these risks may be greater for us than some of our competitors because we sometimes acquire companies that may not have allocated significant resources and management focus to safety and environmental matters and may have a poor environmental and safety record and associated possible exposure. Our insurance may not be adequate to cover all losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not justify its purchase. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations and cash flows. In addition, we may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position.

Since hydraulic fracturing activities are part of our operations, they are covered by our insurance against claims made for bodily injury, property damage and clean-up costs stemming from a sudden and accidental pollution event. However, we may not have coverage if we are unaware of the pollution event and unable to report the “occurrence” to our insurance company within the time frame required under our insurance policy. We have no coverage for gradual, long-term pollution events. In addition, these policies do not provide coverage for all liabilities, and the insurance coverage may not be adequate to cover claims that may arise, or we may not be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

We are subject to extensive environmental, health and safety laws and regulations that may subject us to substantial liability or require us to take actions that will adversely affect our results of operations.

Our business is significantly affected by stringent and complex federal, state and local laws and regulations governing the discharge of substances into the environment or otherwise relating to environmental protection and health and safety matters. As part of our business, we handle, transport and dispose of a variety of fluids and substances, including hydraulic fracturing fluids which can contain hydrochloric acid and certain petrochemicals. This activity poses some risks of environmental liability, including leakage of hazardous substances from the wells to surface and subsurface soils, surface water or groundwater. We also handle, transport and store these substances. The handling, transportation, storage and disposal of these fluids are regulated by a number of laws, including: the Resource Conservation and Recovery Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Clean Water Act; the Safe Drinking Water Act; and other federal and state laws and regulations promulgated thereunder. The cost of compliance with these laws can be significant. Failure to properly handle, transport or dispose of these materials or otherwise conduct our operations in accordance with these and other environmental laws could expose us to substantial liability for administrative, civil and criminal penalties, cleanup and site restoration costs and liability associated with releases of such materials, damages to natural resources and other damages, as well as potentially impair our ability to conduct our operations. We could be exposed to liability for cleanup costs, natural resource damages and other damages under these and other environmental laws. Such liability is commonly on a strict, joint and several liability basis, without regard to fault. Liability may be imposed as a result of our conduct that was lawful at the time it occurred or the conduct of, or conditions caused by, prior operators or other third parties. Environmental laws and regulations have changed in the past, and they are likely to change in the future. If existing environmental requirements or enforcement policies change and become more stringent, we may be required to make significant unanticipated capital and operating expenditures.

Regulation of greenhouse gas emissions could result in increased operating costs and reduced demand for oil and natural gas.

In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases, or GHGs. The Environmental Protection Agency, or the EPA, has finalized a series of GHG monitoring, reporting and emissions control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce emissions of GHGs primarily through the development of GHG emission inventories and/or regional GHG cap-and-trade programs. While we are subject to certain federal GHG monitoring and reporting requirements, our operations currently are not adversely impacted by existing federal, state and local climate change initiatives. For a description of existing and proposed GHG rules and regulations, see "—Regulation of Hydraulic Fracturing."

At the international level, in December 2015, the United States participated in the 21st Conference of the Parties (COP-21) of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Agreement went into effect on November 4, 2016. The Agreement establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement, and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. In addition, substantial limitations on GHG emissions could adversely affect demand for oil and natural gas and, consequently, the services we provide.

In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Furthermore, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damage or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Moreover, climate change may cause more extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels and increased volatility in seasonal temperatures. Extreme weather conditions can interfere with our productivity and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Our business is dependent on our ability to conduct hydraulic fracturing and horizontal drilling activities. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals (also called "proppants") under pressure into formations to fracture the surrounding rock and stimulate production. There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, induced seismic activity, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. However, legislation has been proposed in recent sessions of Congress to amend the federal Safe Drinking Water Act, or SDWA, to repeal the exemption for hydraulic fracturing from the definition of "underground injection," to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. In addition, several states and local jurisdictions in which we operate have adopted or are considering adopting regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids.

If new laws or regulations are adopted that significantly restrict hydraulic fracturing, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as 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 could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal, state or local level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations and also to attendant permitting delays and potential increases in costs, which could reduce the demand for our services. Such legislative or regulatory changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our business, financial condition, results of operations and cash flows. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal, state or local laws governing hydraulic fracturing.

Our operations in our natural sand proppant services business are dependent on our rights and ability to mine our properties and on our having renewed or received the required permits and approvals from governmental authorities and other third parties.

We hold numerous governmental, environmental, mining and other permits, water rights and approvals authorizing operations at our production facilities. For our extraction and processing in Wisconsin, the permitting process is subject to federal, state and local authority. For example, at the federal level, a Mine Identification Request must be filed and obtained before mining commences. If wetlands are implicated, a U.S. Army Corps of Engineers Wetland Permit is required. At the state level, a series of permits are required related to air quality, wetlands, water quality (waste water and storm water), grading, endangered species and archaeological assessments in addition to other permits depending upon site specific factors and operational detail. At the local level, zoning, building, storm water, erosion control, wellhead protection, road usage and access are all regulated and require permitting to some degree. A non-metallic mining reclamation permit is required. A decision by a governmental agency or other third party to deny or delay issuing a new or renewed permit or approval, or to revoke or substantially modify an existing permit or approval, could have a material adverse effect on our ability to continue operations.

Title to, and the area of, mineral properties and water rights may also be disputed. Mineral properties sometimes contain claims or transfer histories that examiners cannot verify. A successful claim that we do not have title to our property or lack appropriate water rights could cause us to lose any rights to explore, develop and extract minerals, without compensation for our prior expenditures relating to such property. Our business may suffer a material adverse effect in the event we have title deficiencies.

In some instances, we have received access rights or easements from third parties, which allow for a more efficient operation than would exist without the access or easement. A third party could take action to suspend the access or easement, and any such action could be materially adverse to our business, results of operations, cash flows or financial condition.

Penalties, fines or sanctions that may be imposed by the U.S. Mine Safety and Health Administration could have a material adverse effect on our proppant production and sales business and our overall financial condition, results of operations and cash flows.

The U.S. Mine Safety and Health Administration, or MSHA, has primary regulatory jurisdiction over commercial silica operations, including quarries, surface mines, underground mines, and industrial mineral process facilities. In addition, MSHA representatives perform at least two annual inspections of our production facilities to ensure employee and general site safety. As a result of these and future inspections and alleged violations and potential violations, we and our suppliers could be subject to material fines, penalties or sanctions. Any of our production facilities or our suppliers' mines could be subject to a temporary or extended shut down as a result of an alleged MSHA violation. Any such penalties, fines or sanctions could have a material adverse effect on our proppant production and sales business and our overall financial condition, results of operations and cash flows.

Increasing trucking regulations may increase our costs and negatively impact our results of operations.

In connection with our business operations, including the transportation and relocation of our energy service equipment and shipment of frac sand, we operate trucks and other heavy equipment. As such, we operate as a motor carrier in providing certain of our services and therefore are subject to regulation by the United States Department of Transportation and by various state agencies. These regulatory authorities exercise broad powers, governing activities such as the authorization to engage in motor carrier operations, driver licensing, insurance requirements, financial reporting and review of certain mergers, consolidations and acquisitions, and transportation of hazardous materials (HAZMAT). Our trucking operations are subject to possible regulatory and legislative changes that may increase our costs. Some of these possible changes include increasingly stringent environmental regulations, changes in the hours of service regulations which govern the amount of time a driver may drive or work in any specific period, onboard black box recorder device requirements or limits on vehicle weight and size. Interstate motor carrier operations are subject to safety requirements prescribed by the United States Department of Transportation. To a large degree, intrastate motor carrier operations are subject to state safety regulations that mirror federal regulations. Matters such as the weight and dimensions of equipment are also subject to federal and state regulations. From time to time, various legislative proposals are introduced, including proposals to increase federal, state, or local taxes, including taxes on motor fuels, which may increase our costs or adversely impact the recruitment of drivers. We cannot predict whether, or in what form, any increase in such taxes applicable to us will be enacted.

Certain motor vehicle operators require registration with the Department of Transportation. This registration requires an acceptable operating record. The Department of Transportation periodically conducts compliance reviews and may revoke registration privileges based on certain safety performance criteria that could result in a suspension of operations.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct mining or drilling activities in some of the areas where we operate.

Oil and natural gas operations in our operating areas can be adversely affected by seasonal or permanent restrictions on mining or drilling activities designed to protect various wildlife, which may limit our ability to operate in protected areas. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. Additionally, the designation of previously unprotected species as threatened or endangered in areas where we operate could result in increased costs arising from species protection measures. Restrictions on oil and natural gas operations to protect wildlife could reduce demand for our services.

Conservation measures and technological advances could reduce demand for oil and natural gas and our services.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas, resulting in reduced demand for oilfield services. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Recently enacted U.S. tax legislation as well as compliance with and future changes in tax law and regulations may adversely affect our business, results of operations, financial condition and cash flow.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act, or the Tax Act, that significantly reforms the Internal Revenue Code of 1986, as amended, or the Code. Among other changes, the Tax Act (i) permanently reduces the U.S. corporate income tax rate, (ii) provides for a transition tax (toll tax) on a one-time “deemed repatriation” of accumulated foreign earnings, (iii) repeals the corporate alternative minimum tax, (iv) imposes new limitations on the utilization of net operating losses, and (v) provides for more general changes to the taxation of corporations, including changes to the deductibility of interest expense, the adoption of a modified territorial tax system, and introducing certain anti-base erosion provisions. The Tax Act is complex and far-reaching, and we cannot predict with certainty the resulting impact its enactment will have on us. The ultimate impact of the Tax Act may differ from our estimates due to changes in interpretations and assumptions made by us as well as additional regulatory guidance that may be issued, and any such changes in our interpretations and assumptions could have an adverse effect on our business, results of operations, financial condition and cash flow.

In addition, we are subject to tax liabilities imposed by multiple jurisdictions, including income taxes, indirect taxes (excise/duty, sales/use and value-added taxes), payroll taxes, franchise taxes, withholding taxes and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted or proposed that could result in increased expenditures for tax liabilities in the future, which could have a material adverse effect on our results of operations, financial condition and cash flows. Additionally, many of these liabilities are subject to periodic audits by the respective taxing authority. Subsequent changes to our tax liabilities as a result of these audits may subject us to interest and penalties.

Losses and liabilities from uninsured or underinsured activities could have a material adverse effect on our financial condition and operations.

The operational insurance coverage we maintain for our business may not fully insure us against all risks, either because insurance is not available or because of the high premium costs relative to perceived risk. Further, any insurance obtained by us may not be adequate to cover any losses or liabilities and this insurance may not continue to be available at all or on terms which are acceptable to us. Insurance rates have in the past been subject to wide fluctuation and changes in coverage could result in less coverage, increases in cost or higher deductibles and retentions. Liabilities for which we are not insured, or which exceed the policy limits of our applicable insurance, could have a material adverse effect on our business activities, financial condition and results of operations.

We may be subject to claims for personal injury and property damage, which could materially adversely affect our financial condition and results of operations.

We operate with most of our customers under master service agreements, or MSAs. We endeavor to allocate potential liabilities and risks between the parties in the MSAs. Generally, under our MSAs, including those relating to our hydraulic fracturing services, we assume responsibility for, including control and removal of, pollution or contamination which originates above surface and originates from our equipment or services. Our customer assumes responsibility for, including control and removal of, all other pollution or contamination which may occur during operations, including that which may result from seepage or any other uncontrolled flow of drilling fluids. We may have liability in such cases if we are negligent or commit willful acts. Generally, our customers also agree to indemnify us against claims arising from their employees' personal injury or death to the extent that, in the case of our hydraulic fracturing operations, their employees are injured or their properties are damaged by such operations, unless resulting from our gross negligence or willful misconduct. Similarly, we generally agree to indemnify our customers for liabilities arising from personal injury to or death of any of our employees, unless resulting from gross negligence or willful misconduct of the customer. In addition, our customers generally agree to indemnify us for loss or destruction of customer-owned property or equipment and in turn, we agree to indemnify our customers for loss or destruction of property or equipment we own. Losses due to catastrophic events, such as blowouts, are generally the responsibility of the customer. However, despite this general allocation of risk, we might not succeed in enforcing such contractual allocation, might incur an unforeseen liability falling outside the scope of such allocation or may be required to enter into an MSA with terms that vary from the above allocations of risk. As a result, we may incur substantial losses which could materially and adversely affect our financial condition and results of operation.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer based programs, including our well operations information and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, whether due to cyberattack or otherwise, possible consequences include our loss of communication links and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss.

The energy services industry has become increasingly dependent on digital technologies to conduct certain processing activities. For example, we depend on digital technologies to perform many of our services and process and record financial and operating data. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our technologies, systems and networks, and those of our vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient. As cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. Our insurance coverage for cyberattacks may not be sufficient to cover all the losses we may experience as a result of such cyberattacks.

Risks Inherent to Our Common Stock

Our two largest stockholders control a significant percentage of our common stock, and their interests may conflict with those of our other stockholders.

Wexford, through its affiliate MEH Sub LLC, and Gulfport beneficially own approximately 56.1% and 25.1%, respectively, of our outstanding common stock. As a result, Wexford alone controls, and Gulfport can exercise significant influence, over matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. Further, two individuals who serve as our directors are affiliates of Wexford or Gulfport. This concentration of ownership and relationships with Wexford and Gulfport make it unlikely that any other holder or group of holders of our common stock will be able to affect the way we are managed or the direction of our business. In addition, we have engaged, and expect to continue to engage, in related party transactions involving Wexford and Gulfport, and certain companies they control. The interests of Wexford and Gulfport with respect to matters potentially or actually involving or affecting us, such as services provided, future acquisitions, financings and other corporate opportunities, and attempts to acquire us, may conflict with the interests of our other stockholders. This concentrated ownership will make it impossible for another company to acquire us and for you to receive any related takeover premium for your shares unless these stockholders approve the acquisition.

A significant reduction by Wexford or Gulfport of their ownership interests in us could adversely affect us.

We believe that Wexford's and Gulfport's substantial ownership interests in us provides them with an economic incentive to assist us to be successful. Neither Wexford nor Gulfport is subject to any obligation to maintain its ownership interest in us and may elect at any time to sell all or a substantial portion of or otherwise reduce its ownership interest in us. If Wexford or Gulfport sells all or a substantial portion of its ownership interest in us, it may have less incentive to assist in our success and its affiliates that serve as members of our board of directors may resign. Such actions could adversely affect our ability to successfully implement our business strategies which could adversely affect our cash flows or results of operations.

We incur increased costs as a result of being a public company, which may significantly affect our financial condition.

We completed our IPO in October 2016. As a public company, we incur significant legal, accounting and other expenses that we did not incur as a private company. These include costs associated with our public company reporting requirements and corporate governance requirements, including requirements under the Sarbanes-Oxley Act of 2002 and the Dodd-Frank Act of 2010, as well as rules implemented by the SEC, The Nasdaq Global Select Market and the Financial Industry Regulatory Authority. These rules and regulations have increased our legal and financial compliance costs and made some activities more time-consuming and costly. These rules and regulations may also make it more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers. We estimate that we incur approximately $2.5 million of incremental costs per year associated with being a publicly traded company; however, it is possible that our incremental costs of being a publicly traded company will be higher than we currently estimate. After we are no longer an "emerging growth company," we expect to incur significant additional expenses and devote substantial management effort toward ensuring compliance with those requirements applicable to companies that are not "emerging growth companies," including Section 404 of the Sarbanes-Oxley Act. See "*—Risks Related to Our Common Stock—We will be subject to certain requirements of Section 404 of the Sarbanes-Oxley Act. If we are unable to timely comply with Section 404 or if the costs related to compliance are significant, our profitability, stock price, results of operations and financial condition could be materially adversely affected*."

For so long as we are an "emerging growth company" we will not be required to comply with certain disclosure requirements that are applicable to other public companies and we cannot be certain if the reduced disclosure requirements applicable to emerging growth companies will make our common stock less attractive to investors.

We are an "emerging growth company," as defined in the JOBS Act and, for as long as we remain an "emerging growth company," intend to take advantage of certain exemptions from various reporting requirements that are applicable to other public companies, including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements, and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and stockholder approval of any golden parachute payments not previously approved. We could be an "emerging growth company" for up to five years following the completion of our IPO, although, if we have more than $1.07 billion in annual revenue, if the market value of our common stock that is held by non-affiliates exceeds $700 million as of June 30 of any year, or we issue more than $1.0 billion of non-convertible debt over a three-year period before the end of that five-year period, we would cease to be an "emerging growth company" as of the following December 31st. We cannot predict if investors will find our common stock less attractive because we rely on certain exemptions available to "emerging growth companies." If some investors find our common stock less attractive as a result, there may be a less active trading market for our common stock and our common stock price may be more volatile.

We are subject to certain requirements of Section 404 of the Sarbanes-Oxley Act. If we are unable to timely comply with Section 404 or if the costs related to compliance are significant, our profitability, stock price, results of operations and financial condition could be materially adversely affected.

As of December 31, 2017, we are required to comply with certain provisions of Section 404 of the Sarbanes-Oxley Act of 2002. Section 404 requires that we document and test our internal control over financial reporting and issue management's assessment of our internal control over financial reporting. Because we are an "emerging growth company," however, our independent registered public accounting firm is not currently required to opine on those internal controls. During the course of our integration of our internal control over financial reporting, we may identify areas requiring improvement, and we may have to design enhanced processes and controls to address issues identified through this review. We believe that the out-of-pocket costs, the diversion of management's attention from running the day-to-day operations and operational changes caused by the need to comply with the requirements of Section 404 of the Sarbanes-Oxley Act could be significant. If the time and costs associated with such compliance exceed our current expectations, our results of operations could be adversely affected.

If we fail to comply with the requirements of Section 404 of the Sarbanes-Oxley Act, or if we or our auditors identify and report material weaknesses in internal control over financial reporting, the accuracy and timeliness of the filing of our annual and quarterly reports may be materially adversely affected and could cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our common stock. In addition, a material weakness in the effectiveness of our internal control over financial reporting could result in an increased chance of fraud and the loss of customers, reduce our ability to obtain financing and require additional expenditures to comply with these requirements, each of which could have a material adverse effect on our business, results of operations and financial condition.

Since we are a "controlled company" for purposes of The Nasdaq Global Select Market's corporate governance requirements, our stockholders will not have, and may never have, the protections that these corporate governance requirements are intended to provide.

Since we are a "controlled company" for purposes of The Nasdaq Global Select Market's corporate governance requirements, we are not required to comply with the provisions requiring that a majority of our directors be independent, the compensation of our executives be determined by independent directors or nominees for election to our board of directors be selected by independent directors. If we choose to take advantage of any or all of these exemptions, our stockholders may not have the protections that these rules are intended to provide.

The corporate opportunity provisions in our certificate of incorporation could enable Wexford, Gulfport or other affiliates of ours to benefit from corporate opportunities that might otherwise be available to us.

Subject to the limitations of applicable law, our certificate of incorporation, among other things:

- permits us to enter into transactions with entities in which one or more of our officers or directors are financially or otherwise interested;
- permits any of our stockholders, officers or directors to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and
- provides that if any director or officer of one of our affiliates who is also one of our officers or directors becomes aware of a potential business opportunity, transaction or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as our director or officer), that director or officer will have no duty to communicate or offer that opportunity to us, and will be permitted to communicate or offer that opportunity to such affiliates and that director or officer will not be deemed to have (i) acted in a manner inconsistent with his or her fiduciary or other duties to us regarding the opportunity or (ii) acted in bad faith or in a manner inconsistent with our best interests.

These provisions create the possibility that a corporate opportunity that would otherwise be available to us may be used for the benefit of one of our affiliates.

We have engaged in transactions with our affiliates and expect to do so in the future. The terms of such transactions and the resolution of any conflicts that may arise may not always be in our or our common stockholders' best interests.

We have engaged in transactions and expect to continue to engage in transactions with affiliated companies. As described elsewhere in this report, including in the notes to our consolidated financial statements, these transactions include, among others, agreements to provide our services and frac sand products to our affiliates and agreements pursuant to which our affiliates provide or will provide us with certain services, including administrative and advisory services and office space. Each of these entities is either controlled by or affiliated with Wexford or Gulfport, as the case may be, and the resolution of any conflicts that may arise in connection with such related party transactions, including pricing, duration or other terms of service, may not always be in our or our stockholders' best interests because Wexford and/or Gulfport may have the ability to influence the outcome of these conflicts. For a discussion of potential conflicts, see "*—Risks Inherent to Our Common Stock—Our two largest stockholders control a significant percentage of our common stock, and their interests may conflict with those of our other stockholders*."

Prior to the IPO, there was no public market for our common stock and if the price of our common stock fluctuates significantly, your investment could lose value.

Prior to the completion of the IPO in October 2016, there was no public market for our common stock. Although our common stock is listed on The Nasdaq Global Select Market, an active public market for our common stock may not be maintained. If an active public market for our common stock is not maintained, the trading price and liquidity of our common stock will be materially and adversely affected. If there is a thin trading market or "float" for our common stock, the market price for our common stock may fluctuate significantly more than the stock market as a whole. Without a large float, our common stock is less liquid than the securities of companies with broader public ownership and, as a result, the trading prices of our common stock may be more volatile. In addition, in the absence of an active public trading market, investors may be unable to liquidate their investment in us. In addition, the stock market is subject to significant price and volume fluctuations, and the price of our common stock could fluctuate widely in response to several factors, including:

- our quarterly or annual operating results;
- changes in our earnings estimates;
- investment recommendations by securities analysts following our business or our industries;
- additions or departures of key personnel;
- changes in the business, earnings estimates or market perceptions of our competitors;
- our failure to achieve operating results consistent with securities analysts' projections;
- changes in industry, general market or economic conditions; and
- announcements of legislative or regulatory change.

The stock market has experienced extreme price and volume fluctuations in recent years that have significantly affected the quoted prices of the securities of many companies, including companies in our industries. The changes often appear to occur without regard to specific operating performance. The price of our common stock could fluctuate based upon factors that have little or nothing to do with our company and these fluctuations could materially reduce the price for our common stock.

Wexford and Gulfport beneficially own a substantial amount of our common stock and may sell such common stock in the public or private markets. Sales of these shares of common stock or sales of substantial amounts of our common stock by other stockholders, or the perception that such sales may occur, could adversely affect the prevailing market price of our common stock.

As of December 31, 2017, Wexford and Gulfport beneficially owned 56.1% and 25.1% shares of our common stock, respectively. Sales of these shares of common stock or sales of substantial amounts of our common stock by other stockholders, or the perception that such sales may occur, could cause the price of our common stock to decline. In addition, the sale of these shares could impair our ability to raise capital through the sale of additional common or preferred stock.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our stock or if our operating results do not meet their expectations, the price of our stock could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our stock or if our operating results do not meet their expectations, our stock price could decline.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

Provisions in our certificate of incorporation and bylaws and Delaware law make it more difficult to effect a change in control of the company, which could adversely affect the price of our common stock.

The existence of some provisions in our certificate of incorporation and bylaws and Delaware corporate law could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders. Our certificate of incorporation and bylaws contain provisions that may make acquiring control of our company difficult, including:

- provisions regulating the ability of our stockholders to nominate directors for election or to bring matters for action at annual meetings of our stockholders;
- limitations on the ability of our stockholders to call a special meeting and act by written consent;
- the ability of our board of directors to adopt, amend or repeal bylaws, and the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained for stockholders to amend our bylaws;
- the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained to remove directors;
- the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained to amend our certificate of incorporation; and
- the authorization given to our board of directors to issue and set the terms of preferred stock without the approval of our stockholders.

These provisions also could discourage proxy contests and make it more difficult for you and other stockholders to elect directors and take other corporate actions. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our common stock.

Our certificate of incorporation designates courts in the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers or other employees.

Our certificate of incorporation provides that, subject to limited exceptions, the Court of Chancery of the State of Delaware will be the sole and exclusive forum for:

- Any derivative action or proceeding brought on our behalf;
- Any action asserting a claim of breach of fiduciary duty owed by any of our directors, officers or other employees to us or our stockholders;
- Any action asserting a claim against us arising pursuant to any provision of the Delaware General Corporation Law; or
- Any other action asserting a claim against us that is governed by the internal affairs doctrine.

In addition, our certificate of incorporation provides that if any action specified above (each is referred to herein as a covered proceeding), is filed in a court other than the specified Delaware courts without the approval of our board of directors (each is referred to herein as a foreign action), the claiming party will be deemed to have consented to (i) the personal jurisdiction of the specified Delaware courts in connection with any action brought in any such courts to enforce the exclusive forum provision described above and (ii) having service of process made upon such claiming party in any such enforcement action by service upon such claiming party's counsel in the foreign action as agent for such claiming party. These provisions may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers or other employees, which may discourage such lawsuits against us and our directors, officers and employees. Alternatively, if a court were to find these provisions of our certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the covered proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business and financial condition.

We do not intend to pay cash dividends on our common stock in the foreseeable future, and therefore only appreciation of the price of our common stock will provide a return to our stockholders.

We currently anticipate that we will retain all future earnings, if any, to finance the growth and development of our business. We do not intend to pay cash dividends in the foreseeable future. Any future determination as to the declaration and payment of cash dividends will be at the discretion of our board of directors and will depend upon our financial condition, results of operations, contractual restrictions, capital requirements, business prospects and other factors deemed relevant by our board of directors. In addition, the terms of our revolving credit facility prohibit us from paying dividends and making other distributions. As a result, only appreciation of the price of our common stock, which may not occur, will provide a return to our stockholders.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Our corporate headquarters are located at 14201 Caliber Drive, Suite 300, Oklahoma City, Oklahoma 73134. We currently own eleven properties, three located in Ohio, four located in Wisconsin, two located in Texas and two located in Canada, which are used for field offices, yards, production plants or housing. In addition to our headquarters, we also lease 25 properties that are used for field offices, yards or transloading facilities for frac sand. We believe that our facilities are adequate for our current operations.

Sand Properties

On May 26, 2017, we acquired substantially all of the assets of Chieftain Sand and Proppant, LLC and Chieftain Sand and Proppant Barron, LLC, unrelated third party sellers, following our successful bid in a bankruptcy court auction, which assets included our Piranha facilities described in more detail below, for approximately $36.3 million. On June 5, 2017, we acquired from Gulfport, Rhino and certain affiliates of Wexford all outstanding membership interests in Sturgeon Acquisitions LLC, which owns Taylor Frac, LLC, Taylor Real Estate Investments, LLC and South River Road, LLC, which acquisition included our Taylor facilities, described in more detail below, in exchange for our issuance of an aggregate of 5,607,452 shares of our common stock to the sellers, with an aggregate value of $103.7 million as of the closing date. These acquisitions expanded our natural sand proppant business operations, added sand reserves and increased our production capacity.

Our natural sand proppant business mines, processes and sells high quality silica, a key input for the hydraulic fracturing of oil and gas wells, which we refer to as frac sand. All of our frac sand facilities are located in Wisconsin, with our Taylor facilities located in Jackson County, our Piranha facilities located in Barron County and our Muskie facilities located in Pierce County. Our frac sand facilities consist of three dry plants with a total permitted capacity of 6.6 million tons of sand per year, and two wet plants that supply two of the dry plants with Northern White silica sand, which we believe is some of the highest quality raw frac sand available. Our Muskie dry plant in Pierce County, Wisconsin also has a wet plant, but is currently supplied by washed sand that is purchased from a third party supplier.

The production of our frac sand consists of three basic processes: mining, wet plant operations and dry plant operations. All mining activities take place in an open pit environment, whereby we remove the topsoil, which is set aside, and then remove other non-economic minerals, or “overburden,” to expose the sand deposits. We then “bump” the sand using explosives on the mine face, which causes the sand to fall into the pit, where it is then carried by truck or conveyor to the wet plant operations. At our wet plants, the mined sand goes through a series of processes designed to separate the sand from unusable materials. The resulting wet sand is then conveyed to a wet sand stockpile where most of the water is allowed to drain into our on-site recycling facility, while the remaining fine grains and materials, if any, are separated through a series of settlement ponds. We reuse the water that does not evaporate in our wet process. Wet sand from our stockpile is then conveyed or trucked to our dry plants where the sand is dried, screened into specific mesh categories and stored in silos. From the silos, we load sand directly into railcars or trucks, which we then ship to one of our transloading facilities or directly to our customers. For information regarding our transloading facilities and shipping capabilities, see “Item 1. Business-Our Services-Natural Sand Proppant Services.”

Taylor. Our Taylor facilities are located in Taylor, Wisconsin and encompass a total of approximately 393 acres. The site contains a mine with 25.0 million tons of proven recoverable proppant sand reserves as of December 31, 2017, based on estimates prepared by John T. Boyd Company, our third party mining and geological consultant. Our Taylor wet plant can currently process up to 1.5 million tons of wet frac sand per year, which will increase to approximately 2.6 million tons per year upon completion of an expansion project which is expected to occur in March 2018. Our Taylor dry plant is adjacent to our Taylor wet plant and wash facilities. As of December 31, 2017, the dry plant had a rated production capacity of 0.9 million tons per year, which will increase to 2.2 million tons per year when the current expansion is complete. Our current air permit allows us to produce up to 2.2 million tons per year of finished product. The current facility has a 100 ton per hour natural gas fluid bed dryer as well as five high capacity gyratory mineral separators, or screeners, that are capable of producing 0.9 million tons of frac sand per year. After our expansion, the facility will have another 150 ton per hour natural gas fluid bed dryer as well as four more high capacity screeners that will be capable capable of producing 1.3 million tons of frac sand per year. Our finished product is transported via truck to our transloading facility with rail access.

Piranha. Our Piranha facilities are located in New Auburn, Wisconsin and encompass a total of approximately 608 acres. The site contains 38.2 million tons of proven recoverable proppant sand reserves as of December 31, 2017, based on estimates prepared by John T. Boyd Company. Our Piranha wet plant, which is adjacent to the mine, can process up to 4.7 million tons of wet sand per year and is located two miles from our Piranha dry plant, to which we have year-round trucking access. As of December 31, 2017, the dry plant facility had a rated production capacity of 2.1 million tons per year, which will increase to 2.6 million tons per year upon completion of upgrades to our dry plant which is expected to occur in mid-2018. Our current air permit allows us to produce up to 3.5 million tons per year of finished product. The current facility has a 150 ton per hour natural gas fired fluid bed dryer and a 90 ton per hour natural gas fired rotary dryer as well as seven high capacity screeners that are capable of producing 2.1 million tons per year. We are currently in the process of upgrading our 90 ton per hour natural gas fired rotary dryer to a 150 ton per hour natural gas fired fluid bed dryer. Our finished product is loaded directly into railcars. Our Piranha facility is capable of storing up to 400 railcars.

Muskie. Our Muskie facilities are located in Plum City, Wisconsin and encompass a total of approximately 40 acres. Although we are currently purchasing washed sand from a third party supplier, our Muskie wet plant can process up to 1.3 million tons of wet sand per year. The site includes an indoor facility capable of washing sand year-round and an enclosed dry plant facility that has a rated production capacity of 2,400 tons per day. Our current air permit allows us to produce up to 0.9 million tons per year of finished product. The facility has a 100 ton per hour natural gas fired fluid bed dryer as well as six high capacity screeners that are capable of producing 0.9 million tons per year. Our finished product is transported via truck to a third-party facility with rail access. The site does not contain any reserves.

Our Wisconsin dry plants are enclosed facilities capable of running year-round, regardless of the weather. Under normal market conditions, we typically operate our plants with work crews of ten to 15 employees. These crews work 40-hour weeks, with shifts between eight and twelve hours, depending on the employee’s function. Because raw sand cannot be wet-processed during extremely cold temperatures, we typically mine and wet-process sand eight months out of the year at our Taylor and Piranha locations. Our Muskie location has an indoor wash facility, which is capable of being run year-round.

Each of our facilities undergoes regular maintenance to minimize unscheduled downtime and to ensure that the quality of our frac sand meets API standards and our customers’ specifications. In addition, we make capital investments in our facilities as required to support customer demand, and our performance goals.

We are currently capable of producing up to 3.9 million dry tons and 7.5 million washed tons of sand per year. After our Taylor and Piranha expansions are complete (which we currently expect to occur in March 2018 and mid-2018, respectively), our aggregate rated dry production capacity at all of our facilities will be 5.7 million tons of sand per year and our aggregate wet production at all of our facilities that currently has such production will be 8.7 million tons of sand per year. The following tables provides information regarding our rated production capacities of our sand production facilities as of December 31, 2017:

Wet Plant Location	**Annual Rated Plant Capacity[c] (Thousands of Tons)**
Taylor in Jackson County, Wisconsin[a]	1,470
Piranha in Barron County, Wisconsin[b]	4,704
Muskie in Pierce County, Wisconsin	1,314

Dry Plant Location	Annual Rated Plant Capacity[c] (Thousands of Tons)
Taylor in Jackson County, Wisconsin[a]	876
Piranha in Barron County, Wisconsin[b]	2,102
Muskie in Pierce County, Wisconsin	876

(a) Annual rated production capacity of our Jackson County wet and dry plants will increase to 2.6 million and 2.2 million tons per year, respectively, when the expansion of the facility is complete, which is expected to occur in March 2018.
(b) We acquired our Barron County plants on May 26, 2017. Annual rated production capacity of our Barron County dry plant will increase to 2.6 million tons per year when certain upgrades to this facility are complete, which is expected to occur in mid-2018.
(c) Once the expansion projects mentioned in notes (a) and (b) above are completed, our annual company-wide rated production capacity is expected to be 5.7 million tons per year and our annual company-wide functional production capacity is expected to be 4.4 million tons per year.

Mineral Reserves

The quantity and nature of the mineral reserves for our Taylor and Piranha properties are estimated by our third-party geologists and mining engineers, while we internally track depletion rate on an interim basis. John T. Boyd Company, a third party mining and geological consultants, estimated our proven sand reserves for our Taylor property as of December 31, 2017, 2016 and 2015 and for our Piranha property, which we acquired in May 2017, as of December 31, 2017, which estimates are set forth in the table below. There were no reserves attributable to our Muskie properties as of December 31, 2017, 2016 and 2015. Our external mining and geological engineers will update our reserve estimates annually, making necessary adjustments for operations at each location during the year and additions or surveying, drill core analysis and other tests to confirm the quantity and quality of the reserves.

	Estimated Proven Reserves (Thousands of Tons)		
Mine Location	December 31, 2017	December 31, 2016	December 31, 2015
Taylor in Jackson County, Wisconsin[a]	25,029	25,844	26,348
Piranha in Barron County, Wisconsin[b]	38,150	N/A	N/A
Total	63,179	25,844	26,348

(a) Prior to our June 5, 2017 Sturgeon acquisition, which included our Taylor facilities, we and Sturgeon were under common control and, as a result, our historical financial information for all periods included in this Annual Report on Form 10-K has been recast to combine Sturgeon's financial results with our financial results as if the acquisition had been effective since Sturgeon commenced operations in September 2014.
(b) We acquired our Piranha mine in Barron County on May 26, 2017.

We categorize our reserves as proven recoverable within SEC definitions. Reserves, as defined by SEC Industry Guide 7, consist of sand which could be economically and legally extracted or produced at the time of the reserve determination. Proven reserves are defined by SEC Industry Guide 7 as those for which (a) the quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established. We have further limited the definition to apply only to sand reserves that we believe could be extracted at an average cost that is economically feasible.

Our proppant sand reserves consist of Northern White silica sand, giving us access to a range of high-quality sand grades meeting or exceeding all API specifications, including a mix between concentrations of coarse grades (20/40 and 30/50 mesh sands) and finer grades (40/70 and 100 mesh). Our sample boring data and our historical production data have indicated that our reserves contain deposits of approximately 40% 40 mesh or coarser substrate. The coarseness and conductivity of Northern White frac sand significantly enhances recovery of oil and liquids-rich gas by allowing hydrocarbons to flow more freely than is sometimes possible with native sand. The low acid-solubility increases the integrity of Northern White frac sand relative to other proppants with higher acid-solubility, especially in shales where hydrogen sulfide and other acidic chemicals are co-mingled with the targeted hydrocarbons. In addition, its crush resistant properties enable Northern White frac sand to be used in deeper drilling applications than the frac sand produced from many native mineral deposits. We believe that the coarseness, conductivity, sphericity, acid-solubility, and crush-resistant properties of our Northern White sand reserves and our facilities' connectivity to rail and other transportation infrastructure afford us an advantage over our competitors and make us one of a select group of sand producers capable of delivering high volumes of frac sand that is optimal for oil and natural gas production to all major unconventional resource basins currently producing throughout North America.

Surface and Mineral Rights

For each of our frac sand facilities, we own surface and mineral rights.

Item 3. Legal Proceedings

Due to the nature of our business, we are, from time to time, involved in other routine litigation or subject to disputes or claims related to our business activities, including workers' compensation claims and employment related disputes. In the opinion of our management, none of the pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

See Part IV, Item 15. Note 16 of this Report.

Item 4. Mine Safety Disclosures

Our operations are subject to the Federal Mine Safety and Health Act of 1977, as amended by the Mine Improvement and New Emergency Response Act of 2006, which imposes stringent health and safety standards on numerous aspects of mineral extraction and processing operations, including the training of personnel, operating procedures, operating equipment and other matters. Our failure to comply with such standards, or changes in such standards or the interpretation or enforcement thereof, could have a material adverse effect on our business and financial condition or otherwise impose significant restrictions on our ability to conduct mineral extraction and processing operations. Following passage of The Mine Improvement and New Emergency Response Act of 2006, MSHA significantly increased the numbers of citations and orders charged against mining operations. The dollar penalties assessed for citations issued has also increased in recent years. Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95.1 to this Report.

PART II. OTHER INFORMATION

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

Market Information

Our common stock is traded on the Nasdaq Global Select Market under the symbol "TUSK." The following table presents the high and low closing prices of our common stock for each quarter in 2017 and 2016 based on the closing price of a given trading day:

2017	High	Low
First Quarter	$ 22.45	$ 15.38
Second Quarter	$ 21.72	$ 16.25
Third Quarter	$ 19.40	$ 11.05
Fourth Quarter	$ 20.89	$ 14.49
2016		
Fourth Quarter [(a)]	$ 17.25	$ 12.48

(a) Our common stock commenced trading on the Nasdaq on October 14, 2016 in connection with our IPO.

Holders of Record

As of the close of business on February 20, 2018, there were four holders of record of our common stock. The number of holders of record of our common stock is not representative of the number of beneficial holders because many of the shares are held by depositories, brokers or nominees. As of December 31, 2017, there were 2,411 beneficial holders of record of our common stock.

Unregistered Sales of Equity Securities

On June 5, 2017, we issued an aggregate of 7.0 million shares of our common stock to the contributors under the Contribution Agreements as consideration for all outstanding membership interests in Sturgeon, Stingray Energy and Stingray Cementing acquired. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations — 2017 Highlights.” These shares of our common stock were issued in reliance upon the exemption from the registration requirements of the Securities Act provided by Section 4(2) of the Securities Act as sales by an issuer not involving any public offering.

Issuer Purchases of Equity Securities

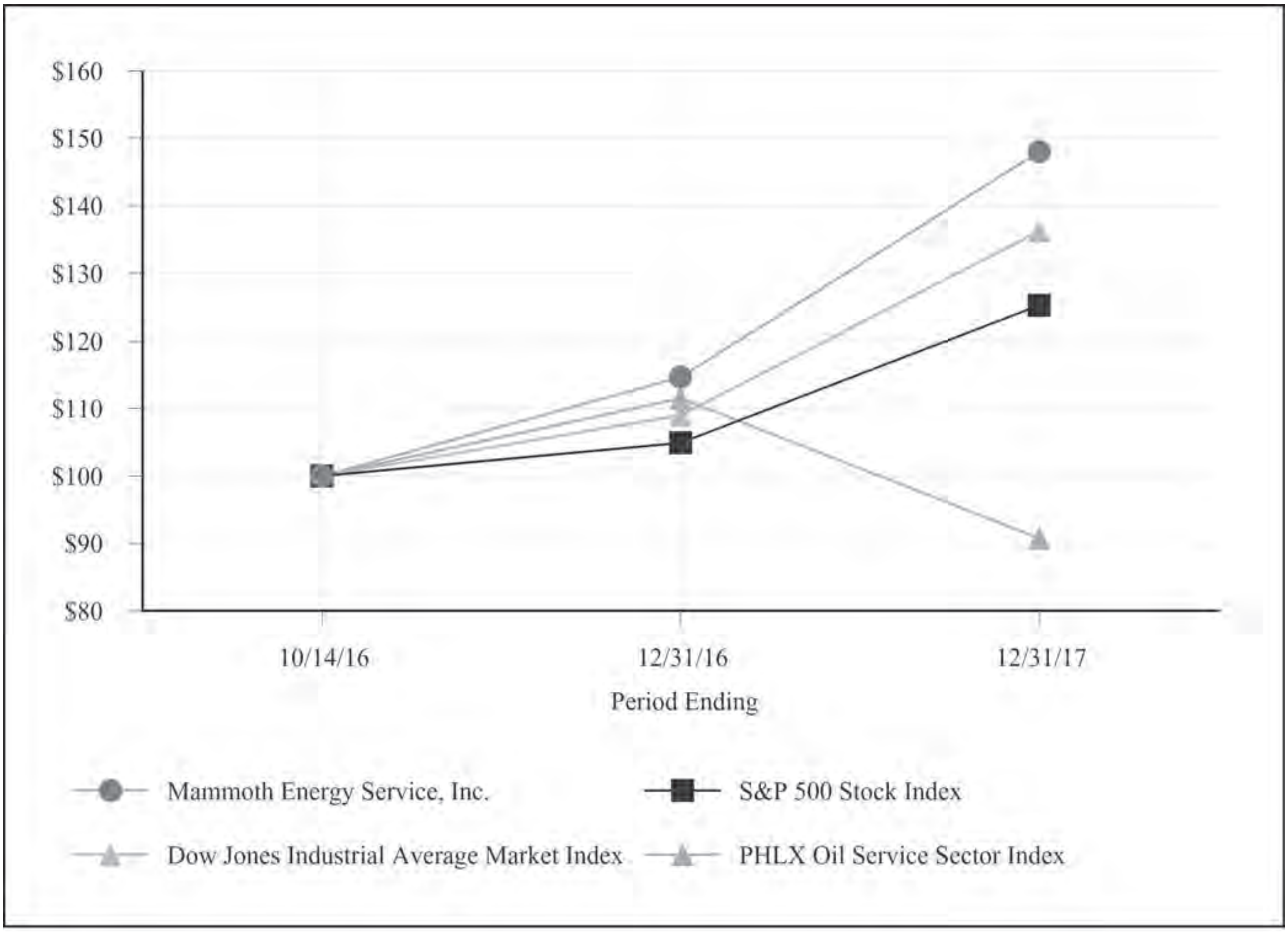
Not applicable.

Dividends

Mammoth Inc. has never declared or paid any cash dividends on its capital stock. We currently intend to retain all available funds and any future earnings for use in the operation and expansion of our business and do not anticipate declaring or paying any cash dividends in the foreseeable future. Any future determination as to the declaration and payment of dividends will be at the discretion of our board of directors and will depend on then-existing conditions, including our financial condition, results of operations, contractual restrictions, capital requirements, business prospects and other factors that our board of directors considers relevant. In addition, the terms of our existing outstanding borrowings restrict the payment of dividends to the holders of our common stock and any other equity holders.

Performance Graph

The following graph and table compares the cumulative total return of a $100 investment in our common stock from October 14, 2016, the date on which our stock began trading on the Nasdaq Global Select Market, through December 31, 2017, with the total cumulative return of a $100 investment in the Standard & Poors 500 Stock Index, the Dow Jones Industrial Average Market Index and the PHLX Oil Service Sector Index during that period.



	October 14, 2016		December 31, 2016		December 31, 2017	
Mammoth Energy Service, Inc.	$	100.00	$	114.63	$	148.04
S&P 500 Stock Index	$	100.00	$	104.88	$	125.25
Dow Jones Industrial Average Market Index	$	100.00	$	108.96	$	136.28
PHLX Oil Service Sector Index	$	100.00	$	111.51	$	90.74

This graph shall not be deemed to be "soliciting material" or to be "filed" with the SEC.

Item 6. Selected Financial Data

This section presents our selected historical combined consolidated financial data. The selected historical combined consolidated financial data presented below is not intended to replace our historical combined consolidated financial statements. You should read the following data along with Item 7. "Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the consolidated financial statements and related notes, each of which is included elsewhere in this annual report.

The historical financial information for periods prior to October 12, 2016, contained in this annual report relates to Mammoth Energy Partners LP, a Delaware limited partnership, or the Partnership. On October 12, 2016, the Partnership was converted into a Delaware limited liability company named Mammoth Energy Partners LLC, or Mammoth LLC, and then each member of Mammoth LLC contributed all of its membership interests in Mammoth LLC to Mammoth Energy Services, Inc., a Delaware corporation, or Mammoth Inc. Prior to the conversion and the contribution, Mammoth Inc. was a wholly-owned subsidiary of the Partnership. Upon the conversion and the contribution, Mammoth LLC (as the converted successor to the Partnership) became a wholly-owned subsidiary of Mammoth Inc.

On October 13, 2016, Mammoth Inc. priced 7,750,000 shares of its common stock in the IPO at a price to the public of $15.00 per share and, on October 14, 2016, Mammoth Inc.'s common stock began trading on The Nasdaq Global Select Market under the symbol "TUSK." On October 19, 2016, Mammoth Inc. closed its IPO. Unless the context otherwise requires, references in this report to "we," "our," "us" or like terms, when used in a historical context for periods prior to October 12, 2016 refer to the Partnership and its subsidiaries. References in this report to "we," "our," "us" or like terms, when used for periods beginning on or after October 12, 2016 refer to Mammoth Inc. and its subsidiaries.

On June 5, 2017, we acquired Sturgeon Acquisitions LLC, or Sturgeon, and Sturgeon's wholly owned subsidiaries Taylor Frac, LLC, Taylor Real Estate Investments, LLC and South River Road, LLC. Prior to the acquisition, we and Sturgeon were under common control and, in accordance with generally accepted accounting principles in the United States, or GAAP, we have accounted for this acquisition in a manner similar to the pooling of interest method of accounting. Therefore, our historical financial information for all periods included in this Annual Report on Form 10-K has been recast to combine Sturgeon's financial results with our financial results as if the acquisition had been effective since Sturgeon commenced operations.

Presented below is our historical financial data for the periods and as of the dates indicated. The historical financial data for the years ended December 31, 2017, 2016, 2015 and 2014 and the balance sheet data as of December 31, 2017, 2016, 2015 and 2014 are derived from our audited consolidated financial statements included elsewhere in this annual report. As an emerging growth company, in accordance with Item 301 of Regulation S-K, historical financial data for the year ended December 31, 2013 and the balance sheet data as of December 31, 2013 are not included in this annual report.

	Years Ended December 31,			
	2017	2016	2015	2014
STATEMENT OF OPERATIONS DATA:	(in thousands, except per share data)			
Total revenues	$ 691,496	$ 230,625	$ 367,937	$ 275,729
Total cost and expenses	$ 628,725	$ 265,255	$ 383,710	$ 253,436
Operating income (loss)	$ 62,771	$ (34,630)	$ (15,773)	$ 22,293
Total other expense	$ (975)	$ (3,938)	$ (7,636)	$ (10,301)
Income (loss) before income taxes	$ 61,796	$ (38,568)	$ (23,409)	$ 11,992
Net income (loss)	$ 58,964	$ (92,453)	$ (21,820)	$ 4,478
Comprehensive income (loss)	$ 59,519	$ (89,742)	$ (26,635)	$ 4,951
Net income (loss) per share (basic)	$ 1.42	$ (2.94)	$ (0.73)	$ 0.21
Net income (loss) per share (diluted)	$ 1.42	$ (2.94)	$ (0.73)	$ 0.21
Weighted average number of shares outstanding (basic)	41,548	31,500	30,000	21,056
Weighted average number of shares outstanding (diluted)	41,639	31,500	30,000	21,056
Pro forma information (unaudited):				
Net (loss) income, as reported		$ (92,453)	$ (21,820)	$ 4,478
Taxes on income earned as a non-taxable entity		$ 15,224	$ 391	$ (7,590)
Taxes due to change to C corporation		$ 53,089	$ —	$ —
Pro forma net loss		$ (24,140)	$ (21,429)	$ (3,112)
Pro forma loss per common share				
Basic and diluted		$ (0.56)	$ (0.50)	$ (0.14)
Weighted average pro forma shares outstanding—basic and diluted		43,107	43,107	22,731
CASH FLOW DATA:				
Cash flows provided by operations	$ 57,616	$ 29,689	$ 69,639	$ 15,853
Cash flows used in investing activities	$ (172,283)	$ (7,718)	$ (27,035)	$ (190,411)
Cash flows provided by provided by (used in) financing activities	$ 91,049	$ 3,075	$ (55,557)	$ 185,911

	December 31,			
	2017	2016	2015	2014
BALANCE SHEET DATA:	(in thousands)			
Cash and cash equivalents	$ 5,637	$ 29,239	$ 4,039	$ 17,219
Property, plant and equipment, net	$ 351,017	$ 242,120	$ 294,883	$ 355,082
Total assets	$ 867,243	$ 502,362	$ 536,412	$ 669,902
Total current liabilities	$ 219,988	$ 29,246	$ 25,433	$ 71,022
Long-term debt	$ 99,900	$ —	$ 95,000	$ 146,041
Total liabilities	$ 359,447	$ 79,581	$ 122,465	$ 225,419
Total equity	$ 507,796	$ 422,781	$ 413,947	$ 444,484

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

The following discussion and analysis should be read in conjunction with the consolidated financial statements and related notes included elsewhere in this Annual Report on Form 10-K. This discussion contains forward-looking statements reflecting our current expectations, estimates and assumptions concerning events and financial trends that may affect our future operating results or financial position. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors, including those discussed in Item 1A. "Risk Factors" and the section entitled "Forward-Looking Statements" appearing elsewhere in this Annual Report on Form 10-K.

Overview

We are an integrated, growth-oriented energy service company serving (i) companies engaged in the exploration and development of North American onshore unconventional oil and natural gas reserves and (ii) government-funded utilities, private utilities, IOUs and Co-Ops through our energy infrastructure business. Our primary business objective is to grow our operations and create value for stockholders through organic opportunities and accretive acquisitions. Our suite of services includes pressure pumping services, infrastructure services, natural sand proppant services, contract land and directional drilling services and other energy services, including coil tubing, flowback, cementing, equipment rental and remote accommodations. Our pressure pumping services division provides hydraulic fracturing services. Our infrastructure services division provides construction, upgrade, maintenance and repair services to the electrical infrastructure industry. Our natural sand proppant services division mines, processes and sells proppant used for hydraulic fracturing. Our contract land and directional drilling services division provides drilling rigs and crews for operators as well as rental equipment, such as mud motors and operational tools, for both vertical and horizontal drilling. In addition to these service divisions, we also provide coil tubing services, pressure control services, flowback services, cementing services, equipment rentals and remote accommodations. We believe that the services we offer play a critical role in increasing the ultimate recovery and present value of production streams from unconventional resources as well as maintaining and improving electrical infrastructure. Our complementary suite of services provides us with the opportunity to cross-sell our services and expand our customer base and geographic positioning.

On November 24, 2014, Mammoth Energy Holdings LLC, or Mammoth Holdings, Gulfport Energy Corporation, or Gulfport, and Rhino Exploration LLC, or Rhino, contributed to the Company their respective interests in the following entities: Bison Drilling and Field Services, LLC, or Bison Drilling; Bison Trucking LLC, or Bison Trucking; White Wing Tubular Services LLC, or White Wing; Barracuda Logistics LLC, or Barracuda; Panther Drilling Systems LLC, or Panther Drilling; Redback Energy Services LLC, or Redback Energy Services; Redback Coil Tubing LLC, or Redback Coil Tubing; Muskie Proppant LLC, or Muskie Proppant; Stingray Pressure Pumping LLC, or Pressure Pumping; Stingray Logistics LLC, or Logistics; and Great White Sand Tiger Lodging Ltd., or Sand Tiger. Upon completion of these contributions, Mammoth Holdings, Gulfport and Rhino beneficially owned a 68.7%, 30.5% and 0.8% equity interest, respectively, in the Partnership. Subsequently, the Partnership formed Redback Pumpdown Services LLC, or Pumpdown, Mr. Inspections LLC, or Mr. Inspections, Silverback Energy Services LLC, or Silverback, and Mammoth Inc. as wholly-owned subsidiaries.

On October 12, 2016, prior to and in connection with the IPO, the Partnership converted to a Delaware limited liability company named Mammoth Energy Partners LLC, or Mammoth LLC, and Mammoth Holdings, Gulfport and Rhino contributed their respective membership interests in Mammoth LLC to us in exchange for shares of our common stock, and Mammoth LLC became our wholly-owned subsidiary.

On October 19, 2016, Mammoth Inc. closed its IPO of 7,750,000 shares of common stock, of which 7,500,000 shares were sold by Mammoth Inc. and the remaining 250,000 shares were sold by certain selling stockholders, at a price to the public of $15.00 per share. Mammoth Inc.'s common stock is traded on the Nasdaq Global Select Market under the symbol "TUSK." Unless the context otherwise requires, references in this report to "we," "our," "us," or like terms, when used in a historical context for periods prior to October 12, 2016 refer to the Partnership and its subsidiaries. References in this report to "we," "our," "us," or like terms, when used in the present tense or for periods commencing on or after October 12, 2016 refer to Mammoth Inc. and its subsidiaries. Mammoth Inc. was formed in June 2016, and did not conduct any material business operations prior to the completion of the IPO and the contribution described below completed on October 12, 2016 immediately prior to the IPO. Prior to the IPO, Mammoth Inc. was a wholly-owned subsidiary of the Partnership.

On June 5, 2017, we acquired Sturgeon Acquisitions LLC, or Sturgeon, and Sturgeon's wholly owned subsidiaries Taylor Frac, LLC, Taylor Real Estate Investments, LLC and South River Road, LLC. Prior to the acquisition, we and Sturgeon were under common control and, in accordance with generally accepted accounting principles in the United States, or GAAP, we have accounted for this acquisition in a manner similar to the pooling of interest method of accounting. Therefore, our historical financial information for all periods included in this Annual Report on Form 10-K has been recast to combine Sturgeon's financial results with our financial results as if the acquisition had been effective since Sturgeon commenced operations.

Our revenues, operating profits and identifiable assets are primarily attributable to four reportable segments: pressure pumping services; infrastructure services; natural sand proppant services; and contract land and directional drilling services. For the year ended December 31, 2016, we identified five reportable segments consisting of pressure pumping services, well services, natural sand proppant services, contract land and directional drilling services and other energy services. We changed our reportable segment presentation in 2017, as we no longer consider well services activities, which included Redback Energy Services, Redback Coil Tubing and Mammoth Energy Partners, and our other energy services activities, which included Sand Tiger, to be significant to the understanding of our results. We now present the results of our well service and other energy service activities as "Other." Additionally, during 2017, we added a new reportable segment for our infrastructure service activities. Segment evaluation is determined on a quantitative basis based on a function of operating income (loss), as well as a qualitative basis, such as nature of the product and service offerings and types of customers. The results of operations for 2016 and 2015 below have been retroactively adjusted to reflect this change in reportable segments.

Since the dates presented below, we have conducted our operations through the following entities:

Pressure Pumping Services Segment
- Pressure Pumping—March 2012
- Logistics—November 2012
- Barracuda—October 2014
- Pumpdown—January 2015
- Mr. Inspections—January 2015
- Silverback—June 2016
- Mammoth Equipment Leasing—November 2016

Infrastructure Services Segment
- Cobra Acquisitions—January 2017
- Cobra Energy—January 2017
- Higher Power Electrical—April 2017
- 5 Star Electric—July 2017

Natural Sand Proppant Services Segment
- Muskie Proppant—September 2011
- Piranha Proppant—May 2017
- Sturgeon Acquisitions—June 2017
- Taylor Frac—June 2017
- Taylor Real Estate Investments—June 2017
- South River Road—June 2017

Contract Land and Directional Drilling Services Segment
- Bison Drilling—November 2010
- Panther Drilling—December 2012
- Bison Trucking—August 2013
- White Wing—September 2014
- Mako Acquisitions—March 2017

Other
- Sand Tiger Lodging—October 2007 (previously included in the Other Energy Services segment)
- Redback Energy Services—October 2011 (previously included in the Well Services segment)
- Redback Coil Tubing—May 2012 (previously included in the Well Services segment)
- Mammoth Energy Partners—June 2016 (previously included in the Well Services segment)
- Stingray Energy Services—June 2017
- Stingray Cementing—June 2017
- Tiger Shark Logistics—October 2017

2017 Highlights

Formation and Expansion of Services with Electric Infrastructure Business

During 2017, we broadened our services offerings by expanding into the electrical infrastructure business with the formation of Cobra Acquisitions LLC, or Cobra, and the acquisitions of Higher Power Electrical, LLC, or Higher Power, in April 2017 and 5 Star Electric, LLC, or 5 Star, in July 2017. On October 19, 2017, Cobra entered into an emergency master services agreement with PREPA for repairs to PREPA's electrical grid as a result of Hurricane Maria. The one-year contract, as amended through February 27, 2018, provides for payments of up to $945.4 million. We, through our subsidiary Cobra, intend to seek additional repair and restoration work for PREPA's electric grid beyond the service provided for in the amendment, as well as work rebuilding and modernizing PREPA's electrical grid once the repair and restoration phase is complete. However, there can be no assurance that we will be successful in securing this additional work. For additional information regarding our services to PREPA, see Item 1. *"Business-Our Services-Infrastructure Services."*

Acquisition of Stingray Energy, Stingray Cementing and Sturgeon

On March 20, 2017, as amended and restated on May 12, 2017, we entered into three definitive contribution agreements, one with Gulfport, Rhino, affiliates of Wexford and Mammoth LLC, and two others with Gulfport, affiliates of Wexford and Mammoth LLC, which we collectively refer to as the Contribution Agreements. Under the Contribution Agreements, we agreed to acquire all outstanding membership interests in Sturgeon (which owns Taylor Frac, LLC, Taylor Real Estate Investments, LLC and South River Road, LLC, which are collectively referred to as Taylor Frac), Stingray Energy Services LLC, or Stingray Energy, and Stingray Cementing LLC, or Stingray Cementing, respectively, for an aggregate of 7.0 million shares of our common stock. These transactions were completed on June 5, 2017. Taylor Frac owns a sand mine and processing plant. Once the expansion of the Taylor facility is completed, which we currently anticipate will occur in March 2018, our company-wide rated production capacity will increase to approximately 5.2 Mmtpa and our functional production capacity will increase to approximately 4.0 Mmtpa of high quality frac sand. Stingray Energy and Stingray Cementing, combined, offer services in fresh water transfer, equipment rental, re-fueling as well as cementing and operate primarily in the Appalachian basin.

Chieftain Acquisition

On March 27, 2017, we entered into a definitive asset purchase agreement, which we refer to as the Purchase Agreement, with Chieftain Sand and Proppant, LLC and Chieftain Sand and Proppant Barron, LLC, unrelated third party sellers, following our successful bid in a bankruptcy court auction for substantially all of the assets of the sellers for $36.3 million, which we refer to as the Chieftain Acquisition. The Chieftain Acquisition closed on May 26, 2017. The assets acquired in the Chieftain Acquisition included a wet and dry plant and sand mine located on approximately 608 acres in New Auburn, Wisconsin. The sellers' facilities are located on the Union Pacific Railroad with unit train capability on site. We funded the purchase price for the Chieftain Acquisition with cash on hand and borrowings under our revolving credit facility. We intend to upgrade certain equipment at our Piranha facility, which is expected to further increase our annual company-wide rated production capacity to 5.7 Mmtpa and our annual company-wide functional production capacity to 4.4 Mmtpa by mid-year 2018.

Expansion of Services into SCOOP/STACK and Permian Basin

During 2017, we expanded our pressure pumping, sand deliveries and last-mile trucking services into the SCOOP/STACK and Permian Basin with the startup of our fourth, fifth and sixth pressure pumping fleets in June, August and October, respectively.

Long Term Take-or-Pay Sand Contracts

During 2017, we signed two take-or-pay sand contracts to sell sand to unrelated third-party service companies covering an aggregate of approximately 1.0 Mmtpa across several grades (20/40, 30/50 and 40/70) of sand. These contract have three year terms ending in 2020.

Overview of Our Industries

Oil and Natural Gas Industry

The oil and natural gas industry has traditionally been volatile and is influenced by a combination of long-term, short-term and cyclical trends, including the domestic and international supply and demand for oil and natural gas, current and expected future prices for oil and natural gas and the perceived stability and sustainability of those prices, production depletion rates and the resultant levels of cash flows generated and allocated by exploration and production companies to their drilling, completion and related services and products budget. The oil and natural gas industry is also impacted by general domestic and international economic conditions, political instability in oil producing countries, government regulations (both in the United States and elsewhere), levels of customer demand, the availability of pipeline capacity and other conditions and factors that are beyond our control.

Demand for most of our oil and natural gas products and services depends substantially on the level of expenditures by companies in the oil and natural gas industry. Oil and natural gas prices experienced a significant decline in prices that began in the third quarter of 2014 and continued into February 2016, when the closing price of oil reached a 12-year low of $26.19 per barrel on February 11, 2016. The low commodity price environment caused a reduction in the drilling, completion and other production activities of most of our customers and their spending on our products and services. During 2017, oil prices rebounded from the lows experienced in 2016 and stabilized in the $42 to $60 per barrel range.

The reduction in demand for, and the resulting oversupply of many of the services and products we provide, substantially reduced the prices we could charge our customers for our products and services, and had a negative impact on the utilization of our services throughout 2016. With the rebound in oil prices from the lows experienced during the first part of 2016, the demand for our suite of services has increased. Prices for oil and natural gas historically have been extremely volatile and are expected to continue to be volatile in the years to come. Throughout 2017, the posted price for West Texas Intermediate light sweet crude oil, which we refer to as WTI, ranged from a low of $42.53 per barrel, or Bbl, on June 21, 2017 to a high of $60.42 per Bbl on December 29, 2017. The recovery in commodity prices has caused the demand for our services to increase. If near term commodity prices stabilize at current levels or continue to increase, we expect to experience further increase in demand for our services and products, particularly in our completion and production, natural sand proppant and contract land and directional drilling businesses.

Energy Infrastructure Industry

In 2017, we expanded into the electric infrastructure business, offering both commercial and storm restoration services to government-funded utilities, private utilities, IOUs and Co-Ops. Since we commenced operations in this line of business, substantially all of our infrastructure revenues has been generated from storm restoration work, including 90% of our infrastructure revenue from PREPA due to the damage by Hurricane Maria. Our contract with PREPA, as amended through February 27, 2018, provides for 2018 revenue of approximately $745 million for services estimated to be performed through mid-2018. Cobra intends to seek additional repair and restoration work for PREPA's electric grid as well as work rebuilding and modernizing PREPA's electric grid once the repair and restoration phase is complete. However, there can be no assurance that Cobra will be successful in securing any additional work. Our inability to secure additional work from PREPA or other governmental authorities in Puerto Rico upon completion of our existing contract would have an adverse effect on our financial condition, results of operations and cash flows.

Natural Sand Proppant Industry

In the natural sand proppant industry, demand growth for frac sand and other proppants is primarily driven by advancements in oil and natural gas drilling and well completion technology and techniques, such as horizontal drilling and hydraulic fracturing, as well as overall industry activity growth. Demand for proppant declined in 2015 and throughout most of 2016 with reduced well completion activity; however, we believe that demand for proppant will continue to grow, as it did throughout 2017, over the long-term. In 2017, several new and existing suppliers announced planned capacity additions of frac sand supply, particularly in the Permian Basin. We expect frac sand supply to lag growth in demand over the coming months and quarters. While planned capacity may exceed the expectations for frac sand demand, the collectively available industry capacity is constrained due to (i) availability of the grades of sand that are currently in demand, (ii) general operating conditions and normal downtime and (iii) logistics constraints. The industry is expected to add capacity over the next 12 to 18 months, particularly in the Permian Basin; however, we do not expect such supply to be available in the volume grades or timeframe needed to efficiently meet the increasing demand.

We believe that the coarseness, conductivity, sphericity, acid-solubility and crush-resistant properties of our Northern White sand reserves and our facilities' connectivity to rail and other transportation infrastructure afford us an advantage over our competitors and make us one of a select group of sand producers capable of delivering high volumes of frac sand that is optimal for oil and natural gas production to all major unconventional resource basins currently producing throughout North America.

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

	Years Ended	
	December 31, 2017	**December 31, 2016**
Revenue:	**(in thousands)**	
Pressure pumping services	$ 279,352	$ 124,425
Infrastructure services	224,425	—
Natural sand proppant services	117,037	38,102
Contract land and directional drilling services	50,521	32,043
Other	51,728	40,970
Eliminations	(31,567)	(4,915)
Total revenue	691,496	230,625
Cost of Revenue:		
Pressure pumping services (exclusive of depreciation and amortization of \$45,381 and \$36,938, respectively, for 2017 and 2016)	211,236	86,888
Infrastructure services (exclusive of depreciation and amortization of \$3,181 and \$0, respectively, for 2017 and 2016)	121,560	—
Natural sand proppant services (exclusive of depreciation, depletion and accretion of \$9,389 and \$6,477, respectively, for 2017 and 2016)	92,780	32,456
Contract land and directional drilling services (exclusive of depreciation of \$19,630 and \$21,481, respectively, for 2017 and 2016)	46,847	31,840
Other (exclusive of depreciation and amortization of \$14,494 and \$7,286, respectively, for 2017 and 2016)	41,678	26,752
Eliminations	(31,532)	(4,915)
Total cost of revenue	482,569	173,021
Selling, general and administrative expenses	49,886	18,048
Depreciation and amortization	92,124	72,315
Impairment of long-lived assets	4,146	1,871
Operating income (loss)	62,771	(34,630)
Interest expense, net	(4,310)	(4,096)
Bargain purchase gain	4,012	—
Other (expense) income, net	(677)	158
Income (loss) before income taxes	61,796	(38,568)
Provision for income taxes	2,832	53,885
Net income (loss)	$ 58,964	$ (92,453)

Revenue. Revenue for 2017 increased $460.9 million, or 200%, to $691.5 million from $230.6 million for 2016. Revenue derived from related parties was $209.0 million, or 30% of our total revenues, for 2017 and $132.9 million, or 58% of our total revenues, for 2016. Substantially all of our related party revenue is derived from Gulfport under our four-year pressure pumping and sand contracts expiring in September 2018. The increase in total revenues was primarily attributable to an expansion of our service offerings into the energy infrastructure business in 2017, representing $224.4 million, or 49%, of the overall increase. Additionally, we organically added three pressure pumping fleets to our pressure pumping segment operations, resulting in an increase in revenues of $100.3 million, or 22% of the consolidated increase, for 2017. Revenues related to 2017 acquisitions, including the Chieftain assets, Stingray Energy and Stingray Cementing, totaled $41.9 million, or 9% of the increase in revenues. The remaining increase in revenues is primarily due to increased utilization across all divisions. Revenue by division was as follows:

Pressure Pumping Services. Pressure pumping services division revenue increased $154.9 million, or 125%, to $279.4 million for 2017 from $124.4 million for 2016. Revenue derived from related parties was $144.5 million, or 52% of total pressure pumping revenues, for 2017 and $102.4 million, or 82% of total pressure pumping revenues, for 2016. Substantially all of our related party revenue is derived from Gulfport under a four-year contract expiring in September 2018. Intersegment revenues, consisting primarily of revenue derived from our sand segment, totaled $2.0 million and $0.6 million, respectively, for 2017 and 2016.

The increase in our pressure pumping services revenue was primarily driven by the startup of our fourth, fifth and sixth pressure pumping fleets in June, August and October 2017, respectively, in the SCOOP/STACK and Permian Basin, which contributed revenues of $100.3 million in 2017. Additionally, fleet utilization increased from 50%, on an average of two active fleets, for 2016 to 72%, on an average of four active fleets, for 2017.

Infrastructure Services. Infrastructure services division revenue was $224.4 million for 2017. We began offering electric utility infrastructure services in 2017 through the formation of Cobra and the acquisitions of Higher Power and 5 Star. We generated $203.1 million, or 90% of total infrastructure services revenue, from our contract with PREPA for repairs to Puerto Rico's electrical grid as a result of Hurricane Maria. We did not provide infrastructure services in 2016.

Natural Sand Proppant Services. Natural sand proppant services division revenue increased $78.9 million, or 207%, to $117.0 million for 2017, from $38.1 million for 2016. Revenue derived from related parties was $43.0 million, or 37% of total sand revenues, for 2017 and $25.8 million, or 68% of total sand revenues, for 2016. Substantially all of our related party revenue is derived from Gulfport under a four-year contract expiring in September 2018. Intersegment revenues, consisting primarily of revenue derived from our pressure pumping segment, totaled $27.0 million, or 23% of total sand revenues, for 2017 and $4.3 million, or 11% of total sand revenues, for 2016.

The increase in our natural sand proppant services revenue was primarily attributable to a 147% increase in tons of sand sold from approximately 683,768 tons in 2016 to 1,690,032 tons in 2017 coupled with a 41% increase in average sales price per ton of sand from $49 in 2016 to $69 in 2017. As previously discussed, we acquired a wet and dry plant and sand mine located on approximately 600 acres in New Auburn, Wisconsin through our purchase of the assets of Chieftain in May 2017. These assets contributed revenues of $22.8 million to our natural sand proppant division in 2017.

Contract Land and Directional Drilling Services. Contract land and directional drilling services division revenue increased $18.5 million, or 58%, to $50.5 million for 2017 from $32.0 million for 2016. Revenue derived from related parties, consisting primarily of directional drilling revenue from Gulfport, was $3.6 million, or 7% of total drilling revenues, for 2017 and $3.9 million, or 12% of total drilling revenues, for 2016. Intersegment revenues, consisting primarily of revenue derived from our pressure pumping segment, totaled $0.4 million for 2017. The contract land and directional drilling services division did not have any intersegment revenues in 2016.

The increase in contract land and direction drilling services revenue was primarily attributable to our land drilling services, which accounted for $10.8 million, or 58%, of the operating division increase. The increase in our land drilling services was driven by an increase in average day rates from approximately $12,900 in 2016 to approximately $14,800 in 2017 as well as an increase in average active rigs from four for 2016 to five for 2017. Our rig moving services accounted for $4.6 million, or 25%, of the operating division increase primarily driven by the increase in drilling activity. Our directional drilling services accounted for $3.3 million, or 18%, of the operating division increase as a result of an increase in utilization from 22% for 2016 to 27% for 2017.

Other. Other revenue, consisting of revenue derived from our coil tubing, pressure control, flowback, cementing, equipment rental and remote accommodation businesses, increased $10.8 million, or 26%, to $51.7 million for 2017 from $41.0 million for 2016. Revenue derived from related parties, consisting primarily of equipment rental and cementing revenue from Gulfport, was $18.0 million, or 35% of total other revenues, for 2017 and $0.9 million, or 2% of total other revenues, for 2016. Intersegment revenues, consisting primarily of revenue derived from our infrastructure and pressure pumping segments, totaled $2.1 million and $0.1 million, respectively, for 2017 and 2016.

Stingray Cementing and Stingray Energy, which we acquired in June 2017, contributed revenues of $19.1 million in 2017. Revenues from our other well services increased $11.9 million in 2017 as compared to 2016 primarily due to increases in utilization. These increases were partially offset by a $20.2 million decrease in revenues for our remote accommodations business primarily due to a decrease in room nights rented from 230,530 in 2016 to 59,721 in 2017.

Cost of Revenue (exclusive of depreciation, depletion, amortization and accretion expense). Cost of revenue increased $309.5 million from $173.0 million, or 75% of total revenue, for 2016 to $482.6 million, or 70% of total revenue, for 2017. The increase was primarily due to an expansion of our service offerings into the infrastructure services business, which represented a $121.6 million increase in cost of revenue, as well as an increase in pressure pumping division costs of $124.3 million, primarily related to the addition of three new fleets and increased utilization of existing fleets, and an increase in natural sand proppant division costs of $60.3 million, primarily due to an increase in tons of sand sold in 2017 compared to 2016. Cost of revenue by division was as follows:

Pressure Pumping Services. Pressure pumping services division cost of revenue increased $124.3 million, or 143%, from $86.9 million for 2016 to $211.2 million for 2017. The increase was primarily due to the expansion of services into the SCOOP/STACK and Permian Basin with the addition of three fleets, which accounted for $90.5 million, or 73% of the increase. As a percentage of revenue, our pressure pumping services division cost of revenue, exclusive of depreciation and amortization expense of $45.4 million in 2017 and $36.9 million in 2016, was 76% and 70%, respectively, for 2017 and 2016. The increase in costs as a percentage of revenue was primarily due to an increase in cost of goods sold as we began selling sand as part of our service package to customers in the mid-continent region in 2017.

Infrastructure Services. Infrastructure services division cost of revenue was $121.6 million for 2017. The largest components of our cost of revenue include labor-related costs, including contract labor, and travel, meals and lodging expense. As a percentage of revenue, cost of revenue, exclusive of depreciation and amortization expense of $3.2 million, was 54% for 2017. We did not provide infrastructure services in 2016.

Natural Sand Proppant Services. Natural sand proppant services division cost of revenue increased $60.3 million, or 186%, from $32.5 million for 2016 to $92.8 million for 2017, primarily due to an increase in cost of goods sold as a result of a 147% increase in tons of sand sold in 2017 compared to 2016, combined with increased production costs per ton of sand in 2017. As a percentage of revenue, cost of revenue, exclusive of depreciation, depletion and accretion expense of $9.4 million in 2017 and $6.5 million in 2016, was 79% and 85%, respectively, for 2017 and 2016. The decrease is primarily due to decreases in labor-related costs and cost of goods sold as a percentage of revenue.

Contract Land and Directional Drilling Services. Contract land and directional drilling services division cost of revenue increased $15.0 million, or 47%, from $31.8 million for 2016 to $46.8 million for 2017, primarily due to an increase in labor-related costs and repairs and maintenance as a result of higher utilization. As a percentage of revenue, our contract land and directional drilling services division cost of revenue, exclusive of depreciation expense of $19.6 million in 2017 and $21.5 million in 2016, was 93% and 99%, respectively, for 2017 and 2016. The decrease was primarily due to a decline in labor-related costs as a percentage of revenue.

Other. Other cost of revenue increased $14.9 million, or 56%, from $26.8 million for 2016 to $41.7 million for 2017, primarily due to the acquisition of Stingray Cementing and Stingray Energy, partially offset by a decrease in costs for our remote accommodation services. As a percentage of revenues, cost of revenue, exclusive of depreciation and amortization expense of $14.5 million in 2017 and $7.3 million in 2016, was 81% and 65%, respectively, for of 2017 and 2016. The increase is primarily the result of increased equipment rental expense and cost of goods sold as a percentage of revenue.

Selling, General and Administrative Expenses. Selling, general and administrative expenses represent the costs associated with managing and supporting our operations. These expenses increased $31.8 million, or 176%, to $49.9 million for 2017, from $18.0 million for 2016. The increase is primarily attributable to a $14.9 million increase in bad debt expense, an $8.2 million increase in compensation and benefits, of which $1.0 million was related to non-cash equity-based compensation, and a $6.1 million increase in professional fees, of which $2.5 million were acquisition-related costs.

Depreciation, Depletion, Amortization and Accretion. Depreciation, depletion, amortization and accretion increased $19.8 million, or 27%, to $92.1 million for 2017 from $72.3 million in 2016. The increase was primarily attributable to $192.6 million in capital additions placed in service in 2017.

Impairment of Long-lived Assets. We recorded impairments of long-lived assets of $4.1 million in 2017, of which $3.8 million related to a drilling rig and $0.3 million related to railroad improvements. Impairments were $1.9 million for 2016, and attributable to various fixed assets.

Operating Income (Loss). Operating income increased $97.4 million, or 281%, to $62.8 million for 2017 compared to an operating loss of $34.6 million for 2016. The increase was primarily the result of an expansion of our service offerings into the infrastructure business, which accounted for 80%, or $78.1 million, of the overall increase in operating income. Operating income from our pressure pumping division increased $17.1 million, or 18% of the overall increase, primarily due to the expansion into the SCOOP/STACK and Permian Basin with the addition of three fleets in 2017 as well as increased utilization for our existing fleets. Operating income for our natural sand proppant division increased $10.5 million, representing an 11% increase overall, primarily due to an increase in sales price per ton of sand sold. Contract land and directional drilling division operating income increased $2.0 million as a result of an increase in our average drilling day rates. These increases were partially offset by a $10.3 million decrease in operating income for our other services, primarily related to a decrease in utilization in our remote accommodations business.

Interest Expense, net. Interest expense increased $0.2 million, or 5%, to $4.3 million during 2017 compared to $4.1 million during 2016. The increase in interest expense was attributable to an increase in average borrowings on our credit facility during 2017.

Bargain Purchase Gain. The purchase of Chieftain resulted in a bargain purchase gain of $4.0 million for 2017. See Note 14 to our consolidated financial statements included elsewhere in this annual report for more information.

Other (Expense) Income, net. Non-operating charges resulted in other (expense) income, net, of ($0.7) million for 2017 compared to $0.2 million for 2016. The 2017 amount included $0.1 million of loss on the disposal of assets during the period compared to a $0.7 million gain for 2016.

Income Taxes. During 2017, we recorded income tax expense of $2.8 million on pre-tax income of $61.8 million compared to income tax expense of $53.9 million on pre-tax loss of $38.6 million for 2016. Our effective tax rate was 4.9% for 2017 and 34.6% for 2016. The decrease in effective tax rate was primarily driven by the recognition of a $31.0 million credit related to the Tax Act enacted in 2017. Additionally, during 2016, in connection with the IPO, we became subject to federal income taxes which triggered recognition of federal income tax liabilities associated with historical earnings (See Note 1 to our consolidated financial statements included elsewhere in this annual report for more information). The 2016 amount included recognition of other items related to the change in classification to a C corporation resulting in total one-time effect of $53.1 million. Additionally, the 2016 amount included recognition of deferred taxes recorded on income from Sand Tiger in the U.S. related to an entity election that required us to disregard previously recorded deferred tax liabilities. See Note 10 to our consolidated financial statements for additional detail regarding our change in tax expense.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

	Years Ended	
	December 31, 2016	December 31, 2015
Revenue:	(in thousands)	
Pressure pumping services	$ 124,425	$ 170,618
Natural sand proppant services	38,102	66,057
Contract land and directional drilling services	32,043	73,033
Other	40,970	64,133
Eliminations	(4,915)	(5,904)
Total revenue	230,625	367,937
Cost of Revenue:		
Pressure pumping services (exclusive of depreciation and amortization of $36,938 and $35,657, respectively, for 2016 and 2015)	86,888	132,129
Natural sand proppant services (exclusive of depreciation, depletion and accretion of $6,477 and $6,298, respectively, for 2016 and 2015)	32,456	47,497
Contract land and directional drilling services (exclusive of depreciation of $21,481 and $24,585, respectively, for 2016 and 2015)	31,840	57,453
Other (exclusive of depreciation and amortization of $7,286 and $7,812, respectively, for 2016 and 2015)	26,752	43,512
Eliminations	(4,915)	(5,904)
Total cost of revenue	173,021	274,687
Selling, general and administrative expenses	18,048	22,400
Depreciation, depletion, accretion and amortization	72,315	74,499
Impairment of long-lived assets	1,871	12,124
Operating loss	(34,630)	(15,773)
Interest expense, net	(4,096)	(5,367)
Other income (expense), net	158	(2,269)
Loss before income taxes	(38,568)	(23,409)
Provision (benefit) for income taxes	53,885	(1,589)
Net loss	$ (92,453)	$ (21,820)

Revenue. Revenue for 2016 decreased $137.3 million, or 37%, to $230.6 million from $367.9 million for 2015. Revenue derived from related parties was $132.9 million, or 58% of our total revenues, for 2016 and $170.7 million, or 46% of our total revenues, for 2015. Substantially all of our related party revenue is derived from Gulfport under four-year pressure pumping and sand contracts expiring in September 2018. The decrease in total revenue was primarily the result of declines in fleet utilization in our pressure pumping and contract land and directional drilling segments and other operations, including coil tubing and flowback. Additionally, our average sales price per ton of sand declined in 2016 compared to 2015. Revenue by division was as follows:

Pressure Pumping Services. Pressure pumping services division revenue decreased $46.2 million, or 27%, to $124.4 million for 2016 from $170.6 million for 2015. Revenue derived from related parties was $102.4 million, or 82% of total pressure pumping revenues, for 2016 and $124.3 million, or 73% of total pressure pumping revenues, for 2015. Substantially all of our related party revenue was derived from Gulfport under a four-year contract expiring in September 2018. Intersegment revenues, consisting primarily of revenues derived from our sand segment, were $0.6 million and $0.8 million, respectively, for 2016 and 2015.

The decrease in our pressure pumping services revenue was driven primarily by a decline in fleet utilization from 63%, on three active fleets, for 2015 to 50%, on two active fleets, for 2016. The division decreases also included decreases due to the suspension of our pump down services in the Woodford Shale in Oklahoma during the fourth quarter of 2015.

Natural Sand Proppant Services. Natural sand proppant services division revenue decreased $28.0 million, or 42%, to $38.1 million for 2016, from $66.1 million for 2015. Revenue derived from related parties was $25.8 million, or 68% of total sand revenues, for 2016 and $38.2 million, or 58% of total sand revenues, for 2015. Substantially all of our related party revenue was derived from Gulfport under a four-year contract expiring in September 2018. Intersegment revenues, consisting primarily of revenues derived from our pressure pumping segment, were $4.3 million and $5.1 million, respectively, for 2016 and 2015.

The decrease in total natural sand proppant services revenue was primarily attributable to a reduction in the average sales price per ton of sand from $94 in 2015 to $49 in 2016. The decrease was partially offset by an increase in tons of sand sold from approximately 651,077 tons for 2015 to approximately 683,768 tons in 2016.

Contract Land and Directional Drilling Services. Contract land and directional drilling services division revenue decreased $41.0 million, or 56%, from $73.0 million for 2015 to $32.0 million for 2016. Revenue derived from related parties, consisting primarily of directional drilling revenue from Gulfport, was $3.9 million, or 12% of total drilling revenues, for 2016 and $4.6 million or 6% of total drilling revenues, for 2015. Our drilling services division did not recognize any intersegment revenues in 2016 and recognized a nominal amount in 2015.

The decrease in total contract land and directional drilling services revenue was primarily attributable to our land drilling services, which accounted for $35.0 million, or 86%, of the operating division decrease. The decrease in our land drilling services was driven by a decline in average active rigs from ten for 2015 to four for 2016 as well as a decline in average day rates from approximately $17,900 to approximately $12,900 during those same years. Our directional drilling services accounted for $4.3 million, or 10%, of the operating division decrease as a result of utilization declining from 36% for 2015 to 22% for 2016. Our rig moving services accounted for $1.2 million, or 3%, of the operating division decrease primarily driven by the decline in drilling activity. Our drill pipe inspection services accounted for $0.5 million, or 1%, of the operating division decrease as a result of this business line being discontinued in the second quarter of 2016.

Other. Other revenue, consisting of revenue derived from our coil tubing, flowback and remote accommodation business, decreased $23.2 million, or 36%, to $41.0 million for 2016 from $64.1 million for 2015. Revenue derived from related parties, consisting primarily of coil tubing and flowback revenue from El Toro Resources LLC, was $0.9 million, or 2% of total other revenues, for 2016 and $3.7 million, or 6% of total other revenues, for 2015. Intersegment revenues, consisting primarily of revenues derived from our pressure pumping segment, were $0.1 million for 2016. We did not recognize any intersegment revenues in 2015.

Our coil tubing division revenue declined as a result of a decrease in average day rates from approximately $25,000 for 2015 to approximately $19,000 for 2016. Our flowback services declined as a result of discontinuing our flowback operations in the Appalachian Basin in December 2015 combined with a decline in both pricing and utilization of such services in other basins. Revenues from our remote accommodations business declined $4.4 million as a result of a decrease in revenue per room night and a decrease in total room nights rented.

Cost of Revenue (exclusive of depreciation, depletion, amortization and accretion). Cost of revenue decreased $101.7 million from $274.7 million, or 75% of total revenue, for 2015 to $173.0 million, or 75% of total revenue, for 2016. This decrease was primarily the result of declines in utilization across all operating divisions. Cost of revenue by division was as follows:

Pressure Pumping Services. Pressure pumping services division cost of revenue decreased $45.2 million, or 34%, from $132.1 million for 2015 to $86.9 million for 2016. The decrease was primarily due to decreases in proppant costs, repairs and maintenance expense and labor-related costs. As a percentage of revenue, our pressure pumping services division cost of revenue, exclusive of depreciation and amortization expense of $37.0 million in 2016 and $35.7 million in 2015, was 70% and 77%, respectively, for 2016 and 2015. The decrease in costs as a percentage of revenue was primarily due to lower repairs and maintenance expense and a decrease in stages completed to 2,442 from 2,963, respectively for 2016 and 2015.

Natural Sand Proppant Services. Natural sand proppant services division cost of revenue decreased $15.0 million, or 32%, from $47.5 million for 2015 to $32.5 million for 2016, primarily due to a decrease in product and processing costs. As a percentage of revenue, cost of revenue, exclusive of depreciation, depletion and accretion expense of $6.5 million in 2016 and $6.3 million in 2015, was 85% and 72%, respectively, for 2016 and 2015.

Contract Land and Directional Drilling Services. Contract land and directional drilling services division cost of revenue decreased $25.6 million, or 45%, from $57.5 million for 2015 to $31.8 million for 2016, primarily due to a decrease in labor-related costs and lower utilization. As a percentage of revenue, our contract land and directional drilling services division cost of revenue, exclusive of depreciation expense of $21.5 million in 2016 and $24.6 million in 2015, was 99% and 79%, respectively, for 2016 and 2015. The increase was primarily due to increased repairs and maintenance and compensation as a percentage of revenue.

Other. Other cost of revenue decreased $16.8 million, or 39%, from $43.5 million for 2015 to $26.8 million for 2016, primarily due to declines in contracted labor-related costs for our remote accommodations business and declines in labor-related costs and repairs and maintenance expense for our coil tubing and flowback businesses. As a percentage of revenues, cost of revenue, exclusive of depreciation and amortization expense of $7.3 million in 2016 and $7.8 million in 2015, was 65% and 68%, respectively, for 2016 and 2015.

Selling, General and Administrative Expenses. Selling, general and administrative expenses represent the costs associated with managing and supporting our operations. These expenses decreased $4.4 million, or 19%, to $18.0 million for 2016, from $22.4 million for 2015. The decrease in expenses was primarily attributable to a $2.5 million reduction in bad debt expense, a $0.3 million reduction in compensation and benefits and reductions in travel-related charges and office and computer support expense of $0.5 million and $0.5 million, respectively, for 2016 compared to 2015.

Depreciation, Depletion, Accretion and Amortization. Depreciation, depletion, accretion and amortization decreased $2.2 million, or 3%, to $72.3 million for 2016 from $74.5 million in 2015. The decrease was primarily attributable to $26.2 million of assets that fully depreciated during 2016 in addition to impairments of $10.2 million in fixed assets during 2015 and was partially offset by $6.6 million of capital additions that were placed in service.

Impairment of Long-lived Assets. We recorded an impairment of long-lived assets in 2016 of $1.9 million, which was attributable to various fixed assets. Impairments for 2015 were $12.1 million, of which $10.2 million was attributable to various fixed assets and $1.9 million was attributable to the termination of a long-term contract.

Operating Loss. Operating loss increased $18.9 million, or 120%, to $34.6 million for 2016 compared to $15.8 million for 2015. The increase in operating loss is primarily attributable to our natural sand proppant division and other services. Natural sand proppant division operating loss increased $10.3 million, representing 54% of the overall increase, primarily due to a 48% decrease in average sales price per ton of sand sold. Other services operating loss increased $7.3 million, or 39% of the overall increase, primarily due to decreases in pricing for our coil tubing, flowback and remote accommodation services.

Interest Expense, net. Interest expense decreased $1.3 million, or 24%, to $4.1 million during 2016 compared to $5.4 million during 2015. The decrease in interest expense was attributable to a decrease in average borrowings during 2016 and the repayment of all outstanding borrowings in October 2016 with a portion of the net proceeds from the IPO.

Other (Expense) Income, net. Non-operating charges resulted in other income, net, of $0.2 million for 2016 compared to other expense, net of $2.3 million for 2015. The 2016 amount included $0.7 million of gain recognition on assets disposed during the period compared to a $1.4 million loss for 2015.

Income Taxes. In 2015, we were treated as a pass-through entity for federal income tax and most state income tax purposes. The income tax expense recognized was primarily attributable to Sand Tiger, which provides our accommodation services. For 2016, we recognized income tax expense of $53.9 million compared to an income tax benefit of $1.6 million for 2015. In 2016, in connection with the IPO, we became subject to federal income taxes which triggered recognition of federal income tax liabilities associated with historical earnings (See Note 1 to our consolidated financial statements included elsewhere in this report for more information). The 2016 amount included recognition of other items related to the change in classification to a C corporation resulting in total one-time effect of $53.1 million. The 2015 amount included recognition of deferred taxes recorded on income from Sand Tiger in the U.S. related to an entity election that required us to disregard previously recorded deferred tax liabilities. We made an election on entity status in September 2015 that allowed the reversal of the deferred taxes in 2015.

Non-GAAP Financial Measures

Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDA as net income (loss) before depreciation, depletion, amortization and accretion expense, impairment of long-lived assets, acquisition related costs, one-time compensation charges associated with the IPO, equity based compensation, bargain purchase gain, interest income, interest expense, other (income) expense, net (which is comprised of the (gain) or loss on disposal of long-lived assets) and provision (benefit) for income taxes. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industries depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income (loss) or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies. We believe that Adjusted EBITDA is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

The following tables also provide a reconciliation of Adjusted EBITDA to the GAAP financial measure of net income or (loss) for each of our operating segments for the specified periods (in thousands).

Consolidated

	Years Ended December 31,		
Reconciliation of Adjusted EBITDA to net income (loss):	**2017**	**2016**	**2015**
Net income (loss)	$ 58,964	$ (92,453)	$ (21,820)
Depreciation, depletion, amortization and accretion	92,124	72,315	74,499
Impairment of long-lived assets	4,146	1,871	12,124
Acquisition related costs	2,506	—	—
One-time IPO compensation charges	—	1,201	—
Equity based compensation	3,741	501	—
Bargain purchase gain	(4,012)	—	—
Interest income	—	—	(98)
Interest expense	4,310	4,096	5,465
Other expense (income), net	677	(158)	2,269
Provision (benefit) for income taxes	2,832	53,885	(1,589)
Adjusted EBITDA	$ 165,288	$ 41,258	$ 70,850

Pressure Pumping Services

	Years Ended December 31,		
Reconciliation of Adjusted EBITDA to net income (loss):	**2017**	**2016**	**2015**
Net income (loss)	$ 11,451	$ (4,568)	$ (5,317)
Depreciation, depletion, amortization and accretion	45,413	37,013	35,729
Impairment of long-lived assets	—	139	1,214
Acquisition related costs	1	—	—
One-time IPO compensation charges	—	102	—
Equity based compensation	1,641	176	—
Interest expense	1,622	599	1,822
Other expense, net	129	27	67
Provision for income taxes	—	—	72
Adjusted EBITDA	$ 60,257	$ 33,488	$ 33,587

Infrastructure Services

Reconciliation of Adjusted EBITDA to net income (loss):	Years Ended December 31, 2017	2016	2015
Net income	$ 48,537	$ —	$ —
Depreciation, depletion, amortization and accretion	3,185	—	—
Acquisition related costs	98	—	—
Equity based compensation	345	—	—
Interest expense	241	—	—
Other expense, net	6	—	—
Provision for income taxes	29,290	—	—
Adjusted EBITDA	$ 81,702	$ —	$ —

Natural Sand Proppant Services

Reconciliation of Adjusted EBITDA to net income (loss):	Years Ended December 31, 2017	2016	2015
Net (loss) income	$ 9,474	$ (4,709)	$ 5,936
Depreciation, depletion, amortization and accretion	9,394	6,483	6,306
Impairment of long-lived assets	324	—	1,905
Acquisition related costs	2,163	—	—
One-time IPO compensation charges	—	33	—
Equity based compensation	708	57	—
Bargain purchase gain	(4,012)	—	—
Interest income	—	—	(98)
Interest expense	679	434	225
Other expense, net	211	96	22
(Benefit) provision for income taxes	(4)	4	—
Adjusted EBITDA	$ 18,937	$ 2,398	$ 14,296

Contract Land and Directional Drilling Services

Reconciliation of Adjusted EBITDA to net income (loss):	Years Ended December 31, 2017	2016	2015
Net loss	$ (27,244)	$ (30,358)	$ (30,401)
Depreciation, depletion, amortization and accretion	19,635	21,512	24,627
Impairment of long-lived assets	3,822	347	8,917
Acquisition related costs	8	—	—
One-time IPO compensation charges	—	964	—
Equity based compensation	507	110	—
Interest expense	1,695	2,829	2,928
Other expense, net	256	248	1,121
Provision (benefit) for income taxes	—	—	(185)
Adjusted EBITDA	$ (1,321)	$ (4,348)	$ 7,007

Other

Reconciliation of Adjusted EBITDA to net income (loss):	Years Ended December 31, 2017	2016	2015
Net income (loss)	$ 16,780	$ (52,820)	$ 7,962
Depreciation, depletion, amortization and accretion	14,497	7,307	7,838
Impairment of long-lived assets	—	1,385	88
Acquisition related costs	237	—	—
One-time IPO compensation charges	—	102	—
Equity based compensation	539	157	—
Interest income	—	—	—
Interest expense	73	234	490
Other expense (income), net	75	(529)	1,059
(Benefit) provision for income taxes	(26,454)	53,881	(1,477)
Adjusted EBITDA	$ 5,747	$ 9,717	$ 15,960

Liquidity and Capital Resources

We require capital to fund ongoing operations, including maintenance expenditures on our existing fleet and equipment, organic growth initiatives, investments and acquisitions. Since November 2014, our primary sources of liquidity have been cash on hand, borrowings under our revolving credit facility and cash flows from operations in addition to our proceeds from our initial public offering. Our primary use of capital has been for investing in property and equipment used to provide our services and to acquire complementary businesses.

As of December 31, 2017, we had outstanding borrowing under our revolving credit facility of $99.9 million, leaving an aggregate of $62.8 million of available borrowing capacity under this facility, after giving effect to $6.5 million of outstanding letters of credit.

The following table summarizes our liquidity as of the dates indicated (in thousands):

	December 31, 2017	2016
Cash and cash equivalents	$ 5,637	$ 29,239
Revolving credit facility availability	169,233	164,354
Less borrowings	(99,900)	—
Less letter of credit facilities (environmental remediation)	(3,582)	(1,375)
Less letter of credit facilities (insurance programs)	(2,486)	(1,636)
Less letter of credit facilities (rail car commitments)	(455)	(455)
Net working capital (less cash)	88,798	30,453
Total	$ 157,245	$ 220,580

As of February 23, 2018, we had net debt of approximately $86.0 million reflecting $94.7 million in borrowings outstanding under our $170.0 million revolving credit facility and $8.7 million of cash on hand.

Liquidity and Cash Flows

The following table sets forth our cash flows for the periods indicated (in thousands):

	Years Ended December 31,		
	2017	2016	2015
Net cash provided by operating activities	$ 57,616	$ 29,689	$ 69,639
Net cash used in investing activities	(172,283)	(7,718)	(27,035)
Net cash provided by (used in) financing activities	91,049	3,075	(55,557)
Effect of foreign exchange rate on cash	16	154	(227)
Net change in cash	$ (23,602)	$ 25,200	$ (13,180)

Operating Activities

Net cash provided by operating activities was $57.6 million, $29.7 million and $69.6 million, respectively, for the years ended December 31, 2017, 2016 and 2015. The change in operating cash flows from 2016 to 2017 was primarily attributable to an increase in net income as a result of increased utilization across all service divisions and the expansion of services with our infrastructure business and in our pressure pumping division in 2017. The decrease in operating cash flows from 2015 to 2016 was primarily attributable to the decrease in net income. The cash generated from working capital changes was primarily attributable to the collection of receivables.

Investing Activities

Net cash used in investing activities was $172.3 million, $7.7 million and $27.0 million, respectively, for the years ended December 31, 2017, 2016 and 2015. Net cash used for acquisitions totaled $39.3 million for 2017. Substantially all remaining cash used in investing activities was used to purchase property and equipment that is utilized to provide our services.

The following table summarizes our capital expenditures by operating division for the periods indicated (in thousands):

	Years Ended December 31,		
	2017	2016	2015
Pressure pumping services[(a)]	$ 85,853	$ 7,673	$ 4,170
Infrastructure services[(b)]	20,144	—	—
Natural sand proppant services[(c)]	16,376	528	2,371
Contract and directional drilling services[(d)]	8,927	2,710	12,651
Other[(e)]	2,553	829	9,260
Total capital expenditures	$ 133,853	$ 11,740	$ 28,452

(a) Capital expenditures primarily for pressure pumping equipment, including three new fleets, for the year ended December 31, 2017 and various pressure pumping equipment for the years ended December 31, 2016 and 2015.
(b) Capital expenditures primarily for truck and equipment purchases for the year ended December 31, 2017.
(c) Capital expenditures include a conveyor and plant additions for the years ended December 31, 2017, 2016 and 2015.
(d) Capital expenditures primarily for upgrades to our rig fleet for the years ended December 31, 2017, 2016 and 2015.
(e) Capital expenditures primarily for equipment upgrades for the years ended December 31, 2017, 2016 and 2015.

Financing Activities

Net cash provided by (used in) financing activities was $91.0 million, $3.1 million and ($55.6) million, respectively, for the years ended December 31, 2017, 2016 and 2015. In 2017, net cash provided by financing activities was primarily attributable to net borrowings under our revolving credit facility of $99.9 million, which was partially offset by the repayment of acquiree debt of $8.9 million. In 2016, net cash provided by financing activities was primarily attributable to net proceeds of $103.1 million from the IPO, offset by net repayments of $95.0 million under our revolving credit facility and $5.0 million in capital distributions. In 2015, net cash used in financing activities was primarily attributable to net repayments of $51.0 million under our revolving credit facility, $3.9 million in capital distributions and $0.6 million in debt issuance costs.

Effect of Foreign Exchange Rate on Cash

The effect of foreign exchange rate on cash was a nominal amount, $0.2 million and ($0.2) million, respectively, for the years ended December 31, 2017, 2016 and 2015. The year-over-year effect was driven primarily by a favorable (unfavorable) shift in the weakness (strength) of the Canadian dollar relative to the U.S. dollar for the cash held in Canadian accounts.

Working Capital

Our working capital totaled $94.4 million and $59.7 million, respectively, at December 31, 2017 and 2016. Our cash balances totaled $5.6 million and $29.2 million, respectively, at December 31, 2017 and 2016.

Our Revolving Credit Facility

We are party to a $170.0 million revolving credit and security agreement, dated as of November 25, 2014 as subsequently amended, with PNC Capital Markets LLC, as lead arranger, PNC Bank, National Association, as the administrative and collateral agent, and the lenders from time-to-time party thereto. Our revolving credit facility matures on November 25, 2019. Borrowings under our revolving credit facility are secured by our and our subsidiaries' assets. The maximum availability for future borrowings under our revolving credit facility is subject to a borrowing base calculation prepared monthly.

Effective as of July 12, 2017, our revolving credit facility was amended, providing us with greater flexibility for permitted acquisitions and permitted indebtedness, increasing the maximum amount credited to the borrowing base for sand inventory and for in-transit inventory and increasing certain default thresholds from $5 million to $15 million.

Interest is payable monthly at a base rate set by the institution's commercial lending group plus an applicable margin. Additionally, at our request, outstanding balances, are permitted to be converted to LIBOR rate plus applicable margin tranches at set increments of $500,000. The LIBOR rate option allows us to select interest periods from one, two, and three or six months. The applicable margin for either the base rate or the LIBOR rate option can vary from 1.5% to 3.0%, based upon a calculation of the excess availability of the line as a percentage of the maximum credit limit.

At December 31, 2017, we had outstanding borrowing under our credit facility of $99.9 million bearing a weighted average interest rate of 4.37%. At December 31, 2017, we had availability of $62.8 million under our revolving credit facility, after giving effect to $6.5 million of outstanding letters of credit.

Our revolving credit facility contains various customary affirmative and restrictive covenants. Among the covenants are two financial covenants, including a minimum interest coverage ratio (3.0 to 1.0), and a maximum leverage ratio (4.0 to 1.0), and minimum availability ($10.0 million). As of December 31, 2017 and 2016, we were in compliance with these covenants.

Capital Requirements and Sources of Liquidity

During 2017, our capital expenditures totaled $133.9 million and included $85.9 million in our pressure pumping segment primarily related to the purchase of three new fleets, $20.1 million in our infrastructure segment primarily related to truck and equipment purchases, $16.4 million in our natural sand proppant services segment for a conveyor and plant additions, $8.9 million in our contract land and directional drilling services segment primarily for upgrades to our rig fleet and $2.6 million for our other businesses primarily related to equipment additions.

With commodity prices beginning to increase in the second half of 2016 and then stabilizing at their current range of $42 to $60 per barrel, we have seen an increase in customer demand for our oil and natural gas services, particularly in our pressure pumping and natural sand proppant services divisions. We have increased our capital budget accordingly and, during 2018, we currently estimate that our aggregate capital expenditures will be approximately $125.0 million. These capital expenditures include $55.5 million in our infrastructure services segment for assets for an additional 68 crews, $23.9 million in our natural sand proppant services segment primarily related to expansion projects, $21.0 million in our pressure pumping segment for various pressure pumping equipment, $9.8 million in our contract land and directional drilling services segment primarily for rig upgrades, $6.8 million for expansion of our rental equipment business into Oklahoma and $5.7 million for coil tubing equipment.

We believe that our cash on hand, operating cash flow and available borrowings under our revolving credit facility will be sufficient to fund our operations for at least the next twelve months. However, future cash flows are subject to a number of variables, and significant additional capital expenditures could be required to conduct our operations. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. Further, we regularly evaluate acquisition opportunities, and the number of opportunities coming to our attention has increased substantially since the IPO. We do not have a specific acquisition budget for 2018 since the timing and size of acquisitions cannot be accurately forecasted, however, we continue to evaluate opportunities, including transactions involving entities controlled by Wexford and Gulfport. Our acquisitions may be undertaken with cash, our common stock or a combination of cash, common stock and/or other consideration. In the event we make one or more acquisitions and the amount of capital required is greater than the amount we have available for acquisitions at that time, we could be required to reduce the expected level of capital expenditures and/or seek additional capital. If we seek additional capital for that or other reasons, we may do so through borrowings under our revolving credit facility, joint venture partnerships, asset sales, offerings of debt or equity securities or other means. We cannot assure you that this additional capital will be available on acceptable terms or at all. If we are unable to obtain funds we need, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to conduct our operations.

Contractual and Commercial Commitments

The following table summarizes our contractual obligations and commercial commitments as of December 31, 2017 (in thousands):

	Total	Less than 1 year	1-3 Years	3-5 Years	More than 5 Years
Contractual obligations:					
Long-term debt (1)	$ 99,900	$ —	$ 99,900	$ —	$ —
Interest and commitment fees on long-term debt (2)	8,738	4,602	4,136	—	—
Capital lease and equipment financing obligations (3)	4,012	1,052	2,234	726	—
Operating lease obligations (4)	65,634	20,407	26,064	15,818	3,345
Purchase commitments (5)	43,088	32,222	10,866	—	—
Capital purchase commitments (6)	19,582	19,582	—	—	—
	$ 240,954	$ 77,865	$ 143,200	$ 16,544	$ 3,345

(1) The long-term debt excludes interest payments.

(2) Assumption of long-term debt balance outstanding as of December 31, 2017 of $99.9 million using the weighted average interest rate as of December 31, 2017 of 4.37%.

(3) Capital lease and equipment financing obligations relate to vehicles and other equipment.

(4) Operating lease obligations primarily relate to rail cars, real estate and other equipment.

(5) Purchase commitments are comprised of $29.7 million for our sand segment, primarily related to annual obligations to purchase minimum amounts of sand, and $13.4 million for our infrastructure segment, primarily related to lodging service obligations.

(6) Obligations arising from capital improvements/equipment purchases.

Off-Balance Sheet Arrangements

Lease Obligations

We lease real estate, rail cars and other equipment under long-term operating leases with varying terms and expiration dates through 2062.

Minimum Purchase Commitments

We have entered into agreements with suppliers that contain minimum purchase obligations. Our failure to purchase the minimum amounts specified may require us to pay shortfall fees. However, the minimum quantities set forth in the agreements are not in excess of our current expected future requirements.

Capital Spend Commitments

We have entered into agreements with suppliers to acquire capital equipment. These commitments are included in our 2018 capital budget discussed under the heading "Capital Requirements and Sources of Liquidity."

Aggregate future minimum lease payments under these agreements in effect at December 31, 2017 are as follows (in thousands):

Year ended December 31:	**Operating Leases**	**Capital Spend Commitments**	**Minimum Purchase Commitments**
2018	$ 20,407	$ 19,582	$ 32,222
2019	14,200	—	10,866
2020	11,864	—	—
2021	9,303	—	—
2022	6,515	—	—
Thereafter	3,345	—	—
	$ 65,634	$ 19,582	$ 43,088

Other Commitments

Subsequent to December 31, 2017, we entered into an agreement to purchase sand from an unrelated third party seller with aggregate commitments of $6.8 million.

Subsequent to December 31, 2017, we entered into rail car, property and equipment lease agreements with aggregate commitments of $6.8 million.

Subsequent to December 31, 2017, we ordered additional capital equipment with aggregate commitments of $21.8 million.

Subsequent to December 31, 2017, our infrastructure business entered into an air charter agreement with aggregate commitments of $1.0 million.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our combined financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our financial statements. See Note 2 of our consolidated financial statements appearing elsewhere in this prospectus for a discussion of additional accounting policies and estimates made by management.

Use of Estimates. In preparing the financial statements, our management makes informed judgments and estimates that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include but are not limited to the Company's sand reserves and their impact on calculating depletion expense, allowance for doubtful accounts, asset retirement obligations, reserves for self-insurance, depreciation and amortization of property and equipment, business combination valuations, amortization of intangible assets, and future cash flows and fair values used to assess recoverability and impairment of long-lived assets, including goodwill.

Revenue Recognition. We generate revenue from multiple sources within our four reportable segments and our other operating entities. In all cases, revenue is recognized when services are performed, collection of the receivables is probable, persuasive evidence of an arrangement exists and the price is fixed and determinable. The majority of our services are sold without warranty or right of return. Under certain customer contracts in our infrastructure services segment, the Company warrants equipment and labor performed for a specified period following substantial completion of the work. Taxes assessed on revenue transactions are presented on a net basis and are not included in revenue. The specific revenue sources are outlined as follows:

> ***Pressure Pumping Services Revenue.*** Pressure pumping services are typically provided based upon a purchase order, contract or on a spot market basis. Services are provided on a day rate, contracted or hourly basis, and revenue is recognized as the work progresses. Jobs for these services are typically short-term in nature and range from a few hours to multiple days. Revenue is recognized upon the completion of each day's work based upon a completed field ticket, which includes the charges for the services performed, mobilization of the equipment to the location and the personnel involved in such services or mobilization. Additional revenue is generated through labor charges and the sale of consumable supplies that are incidental to the service being performed. The labor charges and the use of consumable supplies are reflected on completed field tickets.
>
> ***Infrastructure Revenue.*** Infrastructure services revenues are recognized as the work progresses based on the days completed or as the contract is completed. These services may be provided pursuant to master service agreements, repair and maintenance contracts or fixed price and non-fixed price installation contracts. Pricing under these contracts may be unit priced, cost-plus/hourly (or time and materials basis) or fixed price (or lump sum basis), and the final terms and prices of these contracts are frequently negotiated with the customer. Under unit-based contracts, the utilization of an output-based measurement is appropriate for revenue recognition. Under our cost-plus/hourly and time and materials type contracts, we recognize revenue on an input basis, as labor hours are incurred and services are performed.
>
> ***Natural Sand Proppant Services Revenue***. Natural sand proppant revenues are recognized when legal title passes to the customer, which may occur at the production facility, rail origin or at the destination terminal. At that point, delivery has occurred, evidence of a contractual arrangement exists, the price is fixed and determinable, and collectability is reasonably assured. Amounts received from customers in advance of sand deliveries are recorded as deferred revenue. Customers have the ability to make up contractual short falls by achieving higher-than-contracted volumes over the shortfall window. Contractual shortfall revenue is deemed not probable until the end of the measurement period.
>
> ***Contract Land and Directional Drilling Services Revenue***. Contract drilling services are provided under daywork or footage contracts, and revenue is recognized as the work progresses based on the days completed or the feet drilled, as applicable. Mobilization revenue and costs for daywork and footage contracts are recognized over the days of actual drilling. Directional drilling services are provided on a day rate or hourly basis, and revenue is recognized as work progresses. Proceeds from customers for the cost of oilfield downhole rental equipment that is involuntarily damaged or lost in-hole are reflected as revenues.

Other Revenue. Other services are typically provided based upon a purchase order, contract or on a spot market basis. Services are provided on a day rate, contracted, or hourly basis, and revenue is recognized as the work progresses. Jobs for these services are typically short-term in nature and range from a few hours to multiple days. Our equipment rental services are recognized upon completion of each day's work based on completed field ticket. Revenue from our remote accommodations business is recognized when rooms are occupied and services have been rendered. Advance deposits on rooms and special events are deferred until services are provided to the customer.

Revenues arising from claims for amounts billed in excess of the contract price or for amounts not included in the original contract are recognized when billed less any allowance for uncollectibility. Revenue from such claims is only recognized if it is probable that the claim will result in additional revenue, the costs for the additional services have been incurred, management believes there is a legal basis for the claim and the amount can be reliably estimated. Revenues from such claims are recorded only to the extent that contract costs relating to the claims have been incurred. Historically, we have not billed any customer for amounts not included in the original contract.

The timing of revenue recognition may differ from contract billing or payment schedules, resulting in revenues that have been earned but not billed (“unbilled revenue”) or amounts that have been billed, but not earned (“deferred revenue”).

Allowance for Doubtful Accounts. We regularly review receivables and provide for estimated losses through an allowance for doubtful accounts. In evaluating the level of established reserves, we make judgments regarding our customers’ ability to make required payments, economic events and other factors. As the financial condition of customers change, circumstances develop or additional information becomes available, adjustments to the allowance for doubtful accounts may be required. In the event we were to determine that a customer may not be able to make required payments, we would increase the allowance through a charge to income in the period in which that determination is made. Uncollectable accounts receivable are periodically charged against the allowance for doubtful accounts once final determination is made of their uncollectibility.

Depreciation, Depletion, Amortization and Accretion. In order to depreciate and amortize our property and equipment, we estimate useful lives, attrition factors and salvage values of these items. Our estimates may be affected by such factors as changing market conditions, technological advances in the industries in which we operate or changes in regulations governing such industries. Depletion of our mining property and development costs is calculated using the units-of-production method on estimated measured tons of in-place reserves.

Impairment of Long-Lived Assets. Long-lived assets are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. Recoverability of such assets is evaluated by measuring the carrying amount of the assets against the estimated undiscounted future cash flows associated with the assets. If such evaluations indicate that the future undiscounted cash flow from the assets is not sufficient to recover the carrying value of such assets, the assets are adjusted to their estimated fair values.

Goodwill. Goodwill is tested for impairment annually, or more frequently if events or changes in circumstances indicate that goodwill might be impaired. The impairment test is a two-step process. First, the fair value of each reporting unit is compared to its carrying value to determine whether an indication of impairment exists. If impairment is indicated, then the implied value of the reporting unit’s goodwill is determined by allocating the unit’s fair value to its assets and liabilities as if the reporting unit had been acquired in a business combination. The fair value of the reporting unit is determined using the discounted cash flow approach, excluding interest. The impairment for goodwill is measured as the excess of its carrying value over its implied value.

Asset Retirement Obligations. Mine reclamation costs, future remediation costs for inactive mines or other contractual site remediation costs are accrued based on management’s best estimate at the end of each period of the costs expected to be incurred at a site. Such cost estimates include, where applicable, ongoing care, maintenance and monitoring costs. Changes in estimates at inactive mines are reflected in earnings in the period an estimate is revised.

Share-based Compensation. The share-based compensation program consists of restricted stock units granted to employees and restricted stock units granted to non-employee directors under the Mammoth Energy Services, Inc. 2016 Incentive Plan (the "2016 Plan"). The Company recognizes in its financial statements the cost of employee services received in exchange for restricted stock based on the fair value of the equity instruments as of the grant date. In general, this value is amortized over the vesting period; for grants with a non-substantive service condition, this value is recognized immediately. Amounts are recognized in selling, general, and administrative expenses.

Income Taxes. Prior to our IPO, the Partnership and each of its subsidiaries, except Sand Tiger, was treated as a pass-through entity for federal income tax and most state income tax purposes. Accordingly, income taxes on net earnings were payable by the stockholders, members or partners and are not reflected in the historical financial statements. In connection with our IPO, we became a C corporation subject to federal income taxes, which triggered the recognition of federal income tax liabilities associated with historical earnings. See Notes 1 and 2 to our consolidated financial statements included elsewhere in this annual report for more information. Sand Tiger is subject to corporate income taxes and they are provided in the financial statements based upon Financial Accounting Standards Board, Accounting Standard Codification 740 Income Taxes. As such, deferred tax assets and liabilities are recognized 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 statutory tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of deferred tax assets and liabilities as a result of a change in tax rate is recognized in the period that includes the statutory enactment date. A valuation allowance for deferred tax assets is recognized when it is more likely than not that the benefit of deferred tax assets will not be realized.

We are currently evaluating provisions of the Tax Act enacted in December 2017. The SEC staff issued Staff Accounting Bulletin No. 118 in December 2017, which allows registrants to record provisional amounts for effects of the Tax Act during a one-year measurement period. The Company has completed its accounting for the re-measurement of deferred taxes from the previous rate of 35% to the new rate of 21%. As not all of the necessary information to analyze all income tax effects of the Tax Act related to the recognition of liabilities for taxes on mandatory repatriation is currently available, the amounts recorded related to deemed repatriation of Sand Tiger's earnings in Canada are provisional amounts, which are believed represents a reasonable estimate of the accounting implications of this tax reform. The Company will continue to evaluate the Tax Act and adjust the provisional amounts as additional information is obtained. The ultimate impact of tax reform may differ from the provisional amounts due to changes in interpretations and assumptions, as well as additional regulatory guidance that may be issued. The Company expects to complete its detailed analysis no later than the fourth quarter of 2018.

New Accounting Pronouncements

In July 2015, the FASB issued ASU No. 2015-11, "*Inventory (Topic 330): Simplifying the Measurement of Inventory*," which changes inventory measured using any method other than last-in, first-out (LIFO) or the retail inventory method (for example, inventory measured using first-in, first-out (FIFO) or average cost) at the lower of cost and net realizable value. ASU 2015-11 is effective for annual and interim reporting periods beginning after December 15, 2016, with early adoption permitted. On January 1, 2017, we adopted the ASU and it did not impact our consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers," which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. Subsequent to ASU 2014-09, the FASB issued several related ASU's to clarify the application of the revenue recognition standard. The core principle of the new standard is for the recognition of revenue to depict the transfer of goods or services to customers in amounts that reflect the payment to which the company expects to be entitled in exchange for those goods or services. The new standard will also result in enhanced revenue disclosures, provide guidance for transactions that were not previously addressed comprehensively and improve guidance for multiple-element arrangements. The ASU is effective for annual periods beginning after December 15, 2016, and interim periods within those years. The new standard permits retrospective application using either of the following methodologies: (i) restatement of each prior reporting period presented (full retrospective method) or (ii) recognition of a cumulative-effect adjustment as of the date of initial application (modified retrospective method). In July 2015, the FASB decided to defer the effective date by one year (until 2018). We have evaluated the impact of this ASU on our consolidated financial statements. This evaluation required, among other things, a review of existing contracts we have with our customers within each of our revenue streams identified within our business, including pressure pumping services, infrastructure services, natural sand proppant services, contract land and directional drilling services and other services. We did not identify any changes to our revenue recognition policies that would result in a material effect on the timing of revenue recognition or our financial position, results of operations, net income or cash flows. Additionally, we do not believe further disaggregation of revenue will be required under the new standard. The adoption of this ASU will have an impact on our revenue related disclosures and internal controls over financial reporting as our revenue recognition related disclosures will expand upon adoption of the new standard. We are currently in the process of finalizing documentation of new policies, procedures, systems, controls and data requirements as the standard is implemented. We will be in a position to begin reporting under the new standard beginning in the first quarter of 2018, using the modified retrospective method.

In February 2016, the FASB issued ASU No, 2016-2 "Leases" amending the current accounting for leases. Under the new provisions, all lessees will report a right-of-use asset and a liability for the obligation to make payments for all leases with the exception of those leases with a term of 12 months or less. All other leases will fall into one of two categories: (i) a financing lease or (ii) an operating lease. Lessor accounting remains substantially unchanged with the exception that no leases entered into after the effective date will be classified as leveraged leases. For sale leaseback transactions, a sale will only be recognized if the criteria in the new revenue recognition standard are met. ASU 2016-2 is effective for fiscal years beginning after December 15, 2018, and interim periods within that fiscal year. Early adoption is permitted. This new leasing guidance will impact us in situations where we are the lessee, and in certain circumstances we will have a right-of-use asset and lease liability on our consolidated financial statements. We are currently evaluating the effect the new guidance will have on our consolidated financial statements and results of operations.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The demand, pricing and terms for our products and services are largely dependent upon the level of activity for the U.S. oil and natural gas industry, energy infrastructure industry and natural sand proppant industry. Industry conditions are influenced by numerous factors over which we have no control, including, but not limited to: the supply of and demand for oil and natural gas services, energy infrastructure services and natural sand proppant; the level of construction of transmission lines, substations and distribution networks in the energy infrastructure industry and the level of expenditures of utility companies; the level of prices of, and expectations about future prices for, oil and natural gas and natural sand proppant, as well as energy infrastructure services; the cost of exploring for, developing, producing and delivering oil and natural gas; the expected rates of declining current production; the discovery rates of new oil and natural gas reserves and frac sand reserves meeting industry specifications and consisting of the mesh size in demand; access to pipeline, transloading and other transportation facilities and their capacity; weather conditions; domestic and worldwide economic conditions; political instability in oil-producing countries; environmental regulations; technical advances affecting energy consumption; the price and availability of alternative fuels; the ability of oil and natural gas producers and other users of our services to raise equity capital and debt financing; and merger and divestiture activity in industries in which we operate.

The level of activity in the U.S. oil and natural gas exploration and production, energy infrastructure and natural sand proppant industries is volatile. Expected trends may not continue and demand for our products and services may not reflect the level of activity in these industries. Any prolonged substantial reduction in pricing environment would likely affect demand for our services. A material decline in pricing levels or U.S. activity levels could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Interest Rate Risk

We had a cash and cash equivalents balance of $5.6 million at December 31, 2017. We do not enter into investments for trading or speculative purposes. We do not believe that we have any material exposure to changes in the fair value of these investments as a result of changes in interest rates. Declines in interest rates, however, will reduce future income.

At December 31, 2017, had outstanding borrowings under our credit facility of $99.9 million bearing a weighted average interest rate of 4.37%. A 1% increase or decrease in the interest rate at that time would have increased or decreased our interest expense by approximately $1.0 million per year. We do not currently hedge our interest rate exposure.

Foreign Currency Risk

Our energy services business generates revenue and incurs expenses that are denominated in the Canadian dollar. These transactions could be materially affected by currency fluctuations. Changes in currency exchange rates could adversely affect our consolidated results of operations or financial position. We also maintain cash balances denominated in the Canadian dollar. At December 31, 2017, we had $2.5 million of cash in Canadian accounts. A 10% increase in the strength of the Canadian dollar versus the U.S. dollar would have resulted in an increase in pre-tax income of approximately $0.1 million as of December 31, 2017. Conversely, a corresponding decrease in the strength of the Canadian dollar would have resulted in a comparable decrease in pre-tax income. We have not hedged our exposure to changes in foreign currency exchange rates and, as a result, could incur unanticipated translation gains and losses.

Seasonality

We provide completion and production services as well as contract land and drilling services primarily in the Utica, Permian Basin, Eagle Ford, Marcellus, Granite Wash, Cana Woodford and Cleveland sand resource plays located in the continental U.S. We provide infrastructure services in the northeast, southwest and midwest portions of the United States and in Puerto Rico. We provide remote accommodation services in the oil sands in Alberta, Canada. We serve these markets through our facilities and service centers that are strategically located to serve our customers in Ohio, Texas, Oklahoma, Wisconsin, Minnesota, Kentucky, Puerto Rico and Alberta, Canada. For the years ended December 31, 2017 and 2016, we generated approximately 42% and 84%, respectively, of our revenue from our operations in Ohio, Wisconsin, Minnesota, North Dakota, Pennsylvania, West Virginia and Canada where weather conditions may be severe. As a result, our operations may be limited or disrupted, particularly during winter and spring months, in these geographic regions, which would have a material adverse effect on our financial condition and results of operations. Our operations in Oklahoma and Texas are generally not affected by seasonal weather conditions.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended 2017, 2016 or 2015. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices increase drilling activity in our areas of operations.

Item 8. Financial Statements and Supplementary Data

The information required by this item appears beginning on page F-1 following the signature pages of this report.

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

Not applicable.

Item 9A. Controls and Procedures

Evaluation of Disclosure Control and Procedures

Under the direction of our Chief Executive Officer and Chief Financial Officer, we have established disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act, that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply judgment in evaluating the benefits of possible controls and procedures relative to their costs.

As of December 31, 2017, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of December 31, 2017, our disclosure controls and procedures are effective.

Changes in Internal Controls Over Financial Reporting

There was no change in our internal control over financial reporting (as defined in Rules 13a-15(d) and 15d-15(d) under the Exchange Act) that occurred during the quarter ended December 31, 2017 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting and Attestation Report of the Registered Public Accounting Firm

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2017, management conducted an evaluation of the effectiveness of our internal control over financial reporting. Based on its evaluation, management did not identify any material weaknesses in our internal control over financial reporting and determined that we maintained effective internal control over financial reporting as of December 31, 2017.

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.

As an entity with less than $1 billion in revenue during our last fiscal year, we qualify as an "emerging growth company" as defined in Rule 12b-2 of the Securities Exchange Act of 1934, as amended. As an emerging growth company, we may take advantage of specified reduced reporting and other regulatory requirements for up to five years from our initial public offering that are otherwise applicable generally to public companies. As an emerging growth company, we are taking advantage of the exemption from the auditor attestation requirement on the effectiveness of our system of internal control over financial reporting.

Item 9B. Other Information

Not applicable.

PART III.

Item 10. Directors, Executive Officers and Corporate Governance

Our Executive Officers and Directors

The following table sets forth information with respect to our executive officers and directors as of February 23, 2018.

Name	Age	Position
Arty Straehla	64	Chief Executive Officer and Director
Mark Layton	43	Chief Financial Officer and Secretary
Marc McCarthy	47	Chairman of the Board
Paul Heerwagen	33	Director
James Palm	73	Director
Matthew Ross	64	Director
Arthur Smith	65	Director

Arty Straehla. Arty Straehla has served as our Chief Executive Officer and as a member of our board of directors since our formation on June 3, 2016. Mr. Straehla served as the Chief Executive Officer of the general partner of Mammoth Partners from February 2016 until October 2016. Prior to joining our company, Mr. Straehla was employed as Chief Executive Officer by Serva Group LLC, an oilfield equipment manufacturer, from July 2010 to January 2016. Mr. Straehla was employed by Diamondback Energy Services, Inc. an oilfield services company, from January 2006 to November 2008, where his last position was Chief Executive Officer. In December 2005, Mr. Straehla completed a 26-year career with the Goodyear Tire and Rubber Co. where his last position was the director of consumer tire manufacturing for the North American consumer tire operations. In this capacity, Mr. Straehla oversaw eight tire plants with 12,000 employees, a $2.5 billion operating budget, a $115.0 million capital expenditures budget and a production capacity of 100 million tires per year. Mr. Straehla holds a Bachelor of Science degree in Secondary Education and a Master of Arts degree in History from Oklahoma State University. Mr. Straehla also has a Master of Business Administration degree from Oklahoma City University. We believe Mr. Straehla's executive management experience and broad knowledge of oilfield services, manufacturing and oil and natural gas industries qualify him for service as a member of our board of directors.

Mark Layton. Mark Layton has served as our Chief Financial Officer since our formation on June 3, 2016 and as our Secretary since our IPO in October 2016. Mr. Layton served as the Chief Financial Officer of the general partner of Mammoth Partners from August 2014 until October 2016. Mr. Layton served as Chief Financial Officer of Stingray Pressure Pumping LLC, a subsidiary of the Company, from January 2014 to August 2014. Mr. Layton was employed from August 2011 through January 2014 by Archer Well Company Inc., an oilfield services company, where his last position was Director of Finance for North America. From September 2009 through August 2011, Mr. Layton was employed by Great White Energy Services, Inc., an oilfield services company, where his last position was Corporate Controller and Director of Financial Reporting. Mr. Layton served as Vice President of Finance of Crossroads Wireless, Inc., a wireless telecommunications service company, from May 2007 through September 2009. In February 2009, an involuntary petition under Chapter 7 of the United States Bankruptcy Code was filed against Crossroads Wireless, Inc. in the Western District of Oklahoma. From April 2004 through May 2007, Mr. Layton served as the Director of Financial Reporting for Chickasaw Holding Company, a telecommunications service company. He began his career in public accounting with Finley & Cook PLLC. Mr. Layton has a Bachelor of Science degree in Accounting from the University of Central Oklahoma. Mr. Layton is a Certified Public Accountant.

Marc McCarthy. Marc McCarthy has served as Chairman of the Board of Directors since our formation on June 3, 2016, and served as Chairman of the Board of Directors of the company that was the general partner of Mammoth Energy Partners LP, or Mammoth Partners, from September, 2014 until October 2016. Mr. McCarthy is currently a Partner at Wexford, having joined Wexford in June 2008. Mr. McCarthy has served as a director of Penn Virginia Corporation, an independent exploration and production company, since September 2016. Mr. McCarthy served as a director of Coronado Midstream LLC, a private gas gathering and processing operation in Midland, TX from October 2012 until March 2014. From September 2009 until June 2013, Mr. McCarthy served as Chairman of the Board and a director of EPL Oil & Gas, Inc., an independent oil and natural gas exploration and production company. He also served on the Nominating and Governance Committee of EPL Oil & Gas, Inc. Before joining Wexford, Mr. McCarthy was a Senior Managing Director at Bear Stearns & Co., Inc. within its Global Equity Research Department having been responsible for coverage of the international oil and gas sector. Mr. McCarthy joined Bear Stearns & Co. in 1997 and held various positions of increasing responsibility until his departure in June 2008. Prior to 1997, he worked in equity research at Prudential Securities, also following the oil and gas sector. Mr. McCarthy is a Chartered Financial Analyst and received a B.A. in Economics from Tufts University. We believe Mr. McCarthy's experience as a director of both publicly-traded and private oil and gas companies, as well as his experience in evaluating financial, strategic and operational aspects of companies in the oil and natural gas industry at Wexford, qualifies him for service as a member of our board of directors.

Paul Heerwagen. Paul Heerwagen has served as a director of the Company since January 9, 2017. Mr. Heerwagen serves as Senior Vice President of Corporate Development and Strategy for Gulfport, an independent oil and natural gas exploration and production company. Since joining Gulfport in May 2007, Mr. Heerwagen has served in multiple roles, including as the Director of Investor Relations and Corporate Affairs. In addition, Mr. Heerwagen was involved in the formation of the Stingray entities in 2012 where he served as their President from 2012 to 2014 and oversaw their business operations. Mr. Heerwagen holds a Bachelor of Science degree in Finance from Oklahoma State University. We believe Mr. Heerwagen's corporate strategic planning experience and his experience in the oil and natural gas industry, in particular his experience in the oilfield services business through his prior position with the Stingray entities (which are now are our subsidiaries), qualifies him for service as a member of our board of directors.

James Palm. James Palm has served as one of our directors since June 2017. Mr. Palm most recently served as a director of Gulfport from February 2006 and as Chief Executive Officer of Gulfport from December 2005, in each case until his retirement in February 2014. Prior to joining Gulfport, Mr. Palm pursued oil and gas investments primarily in Oklahoma, the Texas Panhandle and Kansas as the manager and owner of Crescent Exploration, LLC, a company he founded in 1995. Mr. Palm currently serves as a member of the Industry Advisory Committee of the Oklahoma Corporation Commission. From October 2001 through October 2003, Mr. Palm served as the Chairman of the Oklahoma Energy Resources Board. From 1997 through 1999, Mr. Palm served as the President of the Oklahoma Independent Petroleum Association. Mr. Palm received a Bachelor of Science degree in Mechanical Engineering in 1968, and a Masters in Business Administration in 1971, both from Oklahoma State University. We believe that Mr. Palm’s experience in the oil and natural gas industry, as well as his prior management experience, qualifies him for service as a member of our board of directors.

Matthew Ross. Matthew Ross has served as a director of the Company since November 7, 2016. He served as Deputy General Counsel of Deloitte LLP from September 1990 until his retirement in May 2016. In addition, from November 2002 to May 2016, Mr. Ross served as a member of the board of directors of a global captive insurance company, where he chaired the investment committee and was a member of the underwriting committee. Prior to joining Deloitte, from September 1984 to September 1990, Mr. Ross was Associate General Counsel at KPMG and, from September 1978 to September 1984, a corporate attorney at Cravath, Swaine & Moore LLP, where he practiced securities, banking and financing law. Mr. Ross is a member of the advisory board of Schultze Asset Management, LLC. Mr. Ross holds a Bachelor of Science degree in Economics (summa cum laude) from The Wharton School at the University of Pennsylvania and a Doctor of Jurisprudence degree from the University of Virginia Law School. We believe Mr. Ross’s management experience and financial background, combined with his experience in advising on various legal matters, qualifies him for service as a member of our board of directors.

Arthur Smith. Arthur Smith has served as a director of the Company since our IPO in October 2016. He founded Triple Double Advisors, LLC, an investment advisory firm focusing on the energy industry, in 2007 and is its President and Managing Member, a position he has held since August 2007. Mr. Smith was Chairman and Chief Executive Officer of John S. Herold, Inc., an independent energy research firm, from 1984 until the firm was merged into IHS, Inc. in 2007. Prior to that, Mr. Smith was an energy equity analyst at Oppenheimer & Co., Inc. (1982-1984), The First Boston Corp. (1979-1982) and Argus Research Corp. (1976-1979). Since September 2015, Mr. Smith has served on the board of independent crude storage operator, Fairway Energy. Mr. Smith served on the board of directors of Plains All American GP LLC, the general partner of Plains All America Pipeline, L.P., from 1999 until 2010. Mr. Smith is also a former director of PAA Natural Gas Storage, L.P. from April 2010 until December 2013 and Pioneer Southwest Energy Partners, L.P. from May 2008 until December 2013. Mr. Smith is a former director of Pioneer Natural Resources (1993-1998), Cabot Oil & Gas Corporation (1996-2000) and Evergreen Resources, Inc. (2000- 2004), and was a past appointee to the National Petroleum Council. Mr. Smith holds a Bachelor of Administration from Duke University and a Masters of Business Administration from New York University's Stern School of Business. In addition, he holds the Certified Financial Analyst designation. Mr. Smith is a Fellow and active in the National Association of Corporate Directors. We believe that Mr. Smith’s experience with financial matters in the oil and gas industry qualifies him for service as a member of our board of directors.

Investors Rights Agreement

In connection with our IPO, we entered into an investor rights agreement with Gulfport, in which Gulfport, among other things, was granted the right to nominate one of our directors for so long as Gulfport owns 10% or more of our outstanding common stock. Such nominee, if elected to our board of directors, will also serve on each committee of the board of directors so long as he or she satisfies the independence and other requirements for service on the applicable committee. So long as Gulfport has the right to designate a nominee to our board of directors and there is no Gulfport nominee actually serving as our director, Gulfport will have the right to appoint one individual as an advisor to the board of directors who shall be entitled to attend board and committee meetings. One of our directors, Mr. Heerwagen, was nominated by Gulfport pursuant to the investor rights agreement and elected by our stockholders at the 2017 Annual Meeting of Stockholders to serve until the next annual meeting of our stockholders or until his earlier death, resignation or removal.

Our Board of Directors

Our board of directors is elected by the stockholders to direct the business and affairs of the Company. Directors hold office until our next annual meeting of stockholders or until their successors have been otherwise elected or qualified or until the earlier of their death, resignation or removal. The board of directors serves as the ultimate decision-making body of the Company, except for those matters reserved to or shared with the stockholders. The board of directors selects and oversees the executive officers and senior management, who are charged by the board with conducting the business of the Company. Executive officers serve at the discretion of the board of directors. There are no family relationships among any of our directors or executive officers.

Director Independence

Our board of directors has determined that Messrs. Smith, Ross and Palm meet the standards regarding independence set forth in the Nasdaq listing standards and are free of any relationship which, in the opinion of our board of directors, would interfere with the exercise of independent judgment in carrying out their responsibilities as directors of the Company. André Weiss, who served as one of our directors until his resignation in June 2017, also met the foregoing independence standards.

Our board of directors has determined that each member of the Audit Committee is independent for purposes of serving on such committee under the Nasdaq listing standards and applicable federal law. In addition, our board of directors has determined that each current member of the Audit Committee is financially literate under the Nasdaq listing standards and that Mr. Smith qualifies as the "audit committee financial expert," as such term is defined in Item 407(d) of Regulation S-K. Our board of directors has also determined that two of the members of the Compensation Committee meet the independence requirements applicable to those committees under the Nasdaq rules. In addition, our board of directors determined that each of these two members of the Compensation Committee is an "outside director" in accordance with Section 162(m) of the Internal Revenue Code and a "non-employee director" in accordance with Rule 16b-3 under the Securities Exchange Act of 1934, as amended. André Weiss, who served on our board of directors and its Audit Committee and Compensation Committee until his resignation in June 2017, also met the foregoing independence standards with respect to the Audit and Compensation Committees.

Because we are considered to be a controlled company under The Nasdaq Global Select Market rules, we are eligible for exemptions from provisions of these rules requiring a majority of independent directors, nominating and corporate governance and compensation committees composed entirely of independent directors and written charters addressing specified matters. We have elected to take advantage of these exemptions, except that our board of directors has established the Compensation Committee and adopted a written charter for such committee. In the event that we cease to be a controlled company within the meaning of these rules, we will be required to comply with these provisions after the specified transition periods.

Board of Directors Leadership Structure

The positions of Chairman of the Board and Chief Executive Officer are held by two different individuals. Separating these positions allows our Chief Executive Officer to focus on our day-to-day business and operations, while allowing our Chairman of the Board to lead the board in its fundamental role of providing advice to and oversight of management. The Chairman of the Board provides leadership to our board of directors and works with the board of directors to define its structure and activities in the fulfillment of its responsibilities. The Chairman of the Board sets the board agendas, with the input from other members of the board and our management, facilitates communications among and information flow to directors, has the power to call special meetings of our board of directors and stockholders and presides at meetings of our board of directors and stockholders. The Chairman of the Board also advises and counsels our Chief Executive Officer and other officers.

We believe that our directors bring a broad range of leadership experience to the boardroom and regularly contribute to the thoughtful discussion involved in effectively overseeing the business and affairs of the Company. We believe that the atmosphere of our board is collegial, that all board members are well engaged in their responsibilities, and that all board members express their views and consider the opinions expressed by other directors. Three out of six directors on our board are independent under the Nasdaq listing standards and SEC rules, and Mr. Smith has been appointed as the lead director among our independent directors. In such capacity, Mr. Smith's duties include presiding at all meetings of the board at which the Chairman of the Board is not present, including executive sessions of the independent directors, and serving as a liaison between the Chairman of the Board and the independent directors. We believe that all of our independent directors have demonstrated leadership in business enterprises and are familiar with board processes. Mr. Smith, as the chair of our Audit Committee, oversees the accounting and financial reporting processes, as well as compliance with legal and regulatory requirements.

The Compensation Committee is comprised of two independent directors and two additional directors, including the chair. The Compensation Committee oversees the annual performance evaluation of our Chief Executive Officer and Chief Financial Officer as well as our compensation policies and practices and their impact on risk and risk management.

Committees of the Board of Directors

Our board of directors has the following committees:

Committee	Members	Principal Functions
Audit	Arthur Smith * James Palm Matthew Ross	-Reviews and discusses with management and the independent auditors the integrity of our accounting policies, internal controls, financial statements, accounting and auditing processes and risk management compliance. -Monitors and oversees our accounting, auditing and financial reporting processes generally, including the qualifications, independence and performance of the independent auditor. -Monitors our compliance with legal and regulatory requirements. -Establishes procedures for the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls or auditing matters, and the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters. -Reviews and approves related party transactions. -Appoints, determines compensation, evaluates and terminates our independent auditors. -Pre-approves audit and permissible non-audit services to be performed by the independent auditors. -Prepares the report required by the SEC for the inclusion in our annual proxy statement.
Compensation	Marc McCarthy * Paul Heerwagen Arthur Smith James Palm	-Oversees and administers our executive compensation policies, plans and practices and evaluates their impact on risk and risk management. -Discharges the board of directors' responsibilities relating to the compensation of our chief executive officer and other executive officers. -Administers our equity-based compensation plans, including the grants equity awards under such plans. -Makes recommendations to the board with respect to director compensation. -Conducts annual performance evaluation of the committee. -Reviews disclosure related to executive compensation in our proxy statement.

*Committee Chairperson

Code of Business Conduct

We have adopted a Code of Business Conduct and Ethics designed to help directors and employees resolve ethical issues. Our Code of Business Conduct and Ethics applies to all directors and employees, including the Chief Executive Officer, the Chief Financial Officer, controller and persons performing similar functions. The Code of Business Conduct and Ethics covers various topics including, but not limited to, conflicts of interest, fair dealing, discrimination and harassment, confidentiality, compliance procedures and employee complaint procedures and is posted on our website at http://ir.mammothenergy.com/corporate-governance.cfm. We intend to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the Code of Business Conduct and Ethics by posting such information on our website at the address specified above.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our directors and executive officers, and persons who beneficially own more than 10% of a registered class of the Company's equity securities, to file reports of ownership and changes in ownership with the SEC and to furnish us with copies of the forms they file. Two of our stockholders that beneficially owned more than 10% of our common stock, MEH Sub LLC (an affiliate of Wexford) and Gulfport, failed to file a Form 4 on a timely basis disclosing a transaction, but have since filed a Form 4 or Form 5, as applicable, disclosing such transaction. To our knowledge, based solely on a review of the copies of such reports furnished to us and written representations of our officers and directors, all other Section 16(a) reports for the year ended December 31, 2017 applicable to our officers and directors and such other persons were filed on a timely basis.

Item 11. Executive Compensation

As an "emerging growth company," as defined in the Jumpstart our Business Startups Act of 2012, we are not required to include a Compensation Discussion and Analysis section and have elected to comply with the scaled disclosure requirements applicable to emerging growth companies.

Overview

This executive compensation section provides an overview of our executive compensation policy and each element of compensation that we provide.

Executive Compensation Policy

Our general compensation policy is guided by several key principles:

- designing competitive total compensation programs to enhance our ability to attract and retain knowledgeable and experienced senior management level employees;
- motivating employees to deliver outstanding financial performance and meet or exceed general and specific business, operational and individual objectives;
- setting compensation and incentive levels relevant to the market in which the employee provides service; and
- providing a meaningful portion of the total compensation to our named executive officers in equity, thus assuring an alignment of interests between our senior management level employees and our stockholders.

Our compensation committee determines, subject to the terms of the employment agreements with our named executive officers, the mix of compensation, both among short-term and long-term compensation and cash and non-cash compensation, to establish structures that it believes are appropriate for each of our named executive officers. We have not retained compensation consultants to advise us on compensation matters. In making compensation decisions with respect to each element of compensation, the compensation committee considers numerous factors, including:

- the individual's particular background and circumstances, including training and prior relevant work experience;
- the individual's role with us and the compensation paid to similar persons at comparable companies;
- the demand for individuals with the individual's specific expertise and experience at the time of hire;
- achievement of individual and company performance goals and other expectations relating to the position;
- comparison to other executives within our company having similar levels of expertise and experience and the uniqueness of the individual's industry skills; and
- aligning the compensation of our executives with the performance of our company on both a short-term and long-term basis.

In August 2017, our compensation committee engaged Pearl Meyer & Partners, LLC, or Pearl Meyer, to conduct a compensation analysis of compensation practices for our named executive officers and to assist the compensation committee in establishing marketplace compensation levels for such executives in 2018**.** The compensation committee considered any potential conflicts of interest with the compensation consultant and determined that there were no such conflicts of interest. Our compensation committee considered Pearl Meyer's analysis, but has not yet made any compensation decision based on such analysis for 2018.

Employment Agreements

The following summarizes the material employment terms we have with our named executive officers.

Arty Straehla. In February 2016, we entered into an oral employment agreement with Arty Straehla, our Chief Executive Officer, providing for an annual base salary of $400,000, subject to increases from time to time by the board of directors or the compensation committee. Upon completion of our IPO in October 2016, Mr. Straehla's annual base salary was increased to $600,000 and he received an award of 250,000 restricted stock units that vests in three substantially equal annual installments beginning on the first anniversary of the grant. Subject to Mr. Straehla's achievement of certain performance goals to be determined by the board of directors or the compensation committee, Mr. Straehla will be eligible to receive bonuses. Mr. Straehla is entitled to participate in any life and medical insurance plans and other similar plans that we establish from time to time for our executive employees. Mr. Straehla's employment with us is terminable by either party.

Mark Layton. In September 2014, we entered into an oral employment agreement with Mark Layton, our Chief Financial Officer, providing for an initial annual base salary of $225,000. As a result of industry conditions, Mr. Layton's annual base salary was reduced to $202,500 in September 2015. Upon completion of our IPO in October 2016, Mr. Layton's annual base salary was increased to $300,000. Subject to Mr. Layton's achievement of certain performance goals to be determined by the board of directors or the compensation committee, Mr. Layton will be eligible to receive a target annual bonus of 75% of his annual base salary, which bonus could exceed such target in the discretion of the board of directors. In 2017, Mr. Layton received a cash bonus of $200,000 and an equity incentive award of 40,000 restricted stock units that vests in three substantially equal installments beginning on the first anniversary of the grant. Mr. Layton is entitled to participate in any life and medical insurance plans and other similar plans that we establish from time to time for our executive employees. Mr. Layton's employment with us is terminable by either party.

2016 Plan

Prior to the completion of our IPO, we did not have any option or other equity incentive plan and there were no options, restricted units or other equity awards outstanding for any of our named executive officers. In connection with and prior to, our IPO, our board of directors adopted, and our stockholders approved, our equity incentive plan as described below. The equity incentive plan is intended to enable us to obtain and retain the services of employees, directors and consultants who will contribute to our long-term success and to provide an additional incentive to our management and directors to continue to grow our business and enhance the share value for our stockholders.

Eligible award recipients are employees, consultants and directors of our company and its affiliates. Incentive stock options may be granted only to our employees. Awards other than incentive stock options may be granted to employees, consultants and directors. The shares that may be issued pursuant to awards consist of our authorized but unissued common stock, and the maximum aggregate amount of such common stock which may be issued upon exercise of all awards under the plan, including incentive stock options, may not exceed 4,500,000 shares, subject to adjustment to reflect certain corporate transactions or changes in our capital structure. At any time after the Company is subject to the deduction limitations under Section 162(m) of the Internal Revenue Code, the maximum number of shares of common stock issuable under our equity incentive plan to any one participant during a calendar year shall not exceed 450,000 shares.

Share Reserve. The aggregate number of shares of common stock initially authorized for issuance under the plan is 4,500,000 shares. However, (i) shares covered by an award that expires or otherwise terminates without having been exercised in full and (ii) shares that are forfeited to, or repurchased by, us pursuant to a forfeiture or repurchase provision under the plan may return to the plan and be available for issuance in connection with a future award.

Administration. Our board of directors (or our compensation committee or any other committee of the board of directors as may be appointed by our board of directors from time to time) administers the plan. Among other responsibilities, the plan administrator selects participants from among the eligible individuals, determines the type of award and the number of shares that will be subject to each award and determines the terms and conditions of each award, including methods of payment, vesting schedules and limitations and restrictions on awards. The board may amend, suspend, or terminate the plan at any time. Amendments will not be effective without stockholder approval if stockholder approval is required by applicable law or stock exchange requirements. Unless terminated earlier, our equity incentive plan will terminate in August 2026.

Stock Options. Incentive and nonstatutory stock options may be granted pursuant to incentive and nonstatutory stock option agreements. Employees, directors and consultants may be granted nonstatutory stock options, but only employees may be granted incentive stock options. The plan administrator determines the exercise price of a stock option, provided that the exercise price of a stock option cannot be less than 100% (and in the case of an incentive stock option granted to a more than

10% stockholder, 110%) of the fair market value of our common stock on the date of grant, except when assuming or substituting options in limited situations such as an acquisition. Unless otherwise specified by the plan administrator in the terms of any option agreement, options granted under the plan vest ratably over a five-year period and have a term of ten years (five years in the case of an incentive stock option granted to a more than 10% stockholder), unless specified otherwise by the plan administrator in the option agreement.

Acceptable consideration for the purchase of common stock issued upon the exercise of a stock option will be determined by the plan administrator and may include (i) cash or check, (ii) a broker-assisted cashless exercise, (iii) the tender of common stock previously owned by the optionee, (iv) stock withholding and (v) other legal consideration approved by the plan administrator, such as exercise with a full recourse promissory note (not applicable for directors and executive officers).

Unless the plan administrator provides otherwise (solely with respect to inter vivos transfers to certain family members and estate planning vehicles), nonstatutory options generally are not transferable except by will or the laws of descent and distribution. An optionee may designate a beneficiary, however, who may exercise the option following the optionee's death. Incentive stock options are not transferable except by will or the laws of descent and distribution.

Restricted Awards. Restricted awards are awards of either actual shares of common stock (e.g., restricted stock awards), or of hypothetical share units (e.g., restricted stock units) having a value equal to the fair market value of an identical number of shares of common stock, that will be settled in the form of shares of common stock upon vesting or other specified payment date, and which may provide that such restricted awards may not be sold, transferred, or otherwise disposed of for such period as the plan administrator determines. The purchase price and vesting schedule, if applicable, of restricted awards are determined by the plan administrator. A restricted stock unit is similar to a restricted stock award except that participants holding restricted stock units do not have any stockholder rights until the stock unit is settled with shares. Stock units represent an unfunded and unsecured obligation for us and a holder of a stock unit has no rights other than those of a general creditor.

Performance Awards. Performance awards entitle the recipient to vest in or acquire shares of common stock, or hypothetical share units having a value equal to the fair market value of an identical number of shares of common stock that will be settled in the form of shares of common stock upon the attainment of specified performance goals. Performance awards may be granted independent of or in connection with the granting of any other award under the plan. Performance goals will be established by the plan administrator based on one or more business criteria specified in the plan that apply to the plan participant, a business unit, or our company and our affiliates. Performance goals will be objective and will be intended to meet the requirements of Section 162(m) of the Code. Performance goals must be determined prior to the time 25% of the service period has elapsed but not later than 90 days after the beginning of the service period. No payout will be made on a performance award granted to a named executive officer unless all applicable performance goals and service requirements are achieved. Performance awards may not be sold, assigned, transferred, pledged or otherwise encumbered and terminate upon the termination of the participant's service to us or our affiliates.

Stock Appreciation Rights. Stock appreciation rights may be granted independent of or in tandem with the granting of any option under the plan. Stock appreciation rights are granted pursuant to stock appreciation rights agreements. The exercise price of a stock appreciation right granted independent of an option is determined by the plan administrator, but will be no less than 100% of the fair market value of our common stock on the date of grant. The exercise price of a stock appreciation right granted in tandem with an option is the same as the exercise price of the related option. Upon the exercise of a stock appreciation right, we will pay the participant an amount equal to the product of (i) the excess of the per share fair market value of our common stock on the date of exercise over the strike price, multiplied by (ii) the number of shares of common stock with respect to which the stock appreciation right is exercised. Payment will be made in cash, delivery of stock, or a combination of cash and stock as deemed appropriate by the plan administrator.

Adjustments in capitalization. In the event that there is a specified type of change in our common stock without the receipt of consideration by us, such as pursuant to a merger, consolidation, reorganization, recapitalization, reincorporation, stock dividend, dividend in property other than cash, stock split, liquidating dividend, combination of shares, exchange of shares, change in corporate structure or other transaction, appropriate adjustments will be made to the various limits under, and the share terms of, the plan including (i) the number and class of shares reserved under the plan, (ii) the maximum number of stock options and stock appreciation rights that can be granted to any one person in a calendar year and (iii) the number and class of shares and exercise price, strike price, or purchase price, if applicable, of all outstanding stock awards.

Corporate Transactions. In the event of a change in control transaction, or a corporate transaction such as a dissolution or liquidation of our company, or any corporate separation or division, including, but not limited to, a split-up, a split-off or a spin-off, or a sale in one or a series of related transactions, of all or substantially all of the assets of our company or a merger, consolidation, or reverse merger in which we are not the surviving entity, then all outstanding stock awards under the plan may be assumed, continued or substituted for by any surviving or acquiring entity (or its parent company), or may be cancelled either with or without consideration for the vested portion of the awards, all as determined by the plan administrator. In the event an award would be cancelled without consideration paid to the extent vested, the award recipient may exercise the award in full or in part for a period of ten days.

Equity Compensation Plan Information

The following table summarizes information about our equity compensation plan as of December 31, 2017:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders(1)			
Equity Incentive Plan	636,805	N/A	3,756,109

(1) Our board of directors adopted, and our stockholders approved, our equity incentive plan in connection with and prior to our IPO.

401(k) Plan

We have a retirement savings plan in which our named executive officers currently participate. The retirement plan is a tax qualified 401(k) plan that covers all eligible employees including the named executive officers. Prior to October 9, 2015, we made a safe harbor contribution equal to 3% of each eligible employee's gross annual compensation for the prior calendar year, subject to certain limitations provided by our 401(k) plan and Internal Revenue Service regulations. The safe harbor contributions were made regardless of employee's deferrals into the plan. All safe harbor contributions made by us on behalf of an eligible employee were 100% vested when contributed. We also have the ability to make an additional, discretionary contribution that is allocated based on each eligible employee's gross annual compensation for the prior calendar year, but did not make any discretionary contributions in 2015, 2016 or 2017. Effective October 9, 2015, the plan no longer provides for a safe harbor qualified non-elective contributions by us, and we suspended making such safe harbor contributions on behalf of eligible employees beginning on such date. Effective January 1, 2018, we reinstated matching contributions of up to 3% of an eligible employee's compensation.

Effect of Our Compensation Policies and Practices on Risk and Risk Management

The Compensation Committee reviews the risks and rewards associated with our compensation policies and programs. The Compensation Committee believes that such policies and programs encourage and reward prudent business judgment and appropriate risk-taking over the long term and that the Company does not utilize compensation policies and programs creating risks that are reasonably likely to have a material adverse impact on the Company.

SUMMARY COMPENSATION TABLE

The following table provides information concerning compensation of our principal executive officer and our principal financial officer for the fiscal years ended December 31, 2017 and 2016. During 2017, we did not have any other executive officers or persons performing similar functions.

Name and Principal Position	Year	Salary ($)	Bonus(1) ($)	Stock Awards(2) ($)	All Other Compensation(3) ($)	Total ($)
Arty Straehla, Chief Executive Officer	2017	$ 600,000	$ 400,000	$ —	$ 27,264	$ 1,027,264
	2016	$ 400,770	$ —	$ 3,750,000	$ —	$ 4,150,770
Mark Layton, Chief Financial Officer	2017	$ 300,000	$ 200,000	$ 847,200	$ —	$ 1,347,200
	2016	$ 221,626	$ 350,000	$ 225,000	$ —	$ 796,626

(1) The amount awarded to Mr. Layton for 2016 consists of a discretionary bonus of $50,000 and a one-time bonus of $300,000 awarded in connection with the successful completion of our IPO. The amount awarded to Mr. Layton for 2017 consists of a cash bonus of $200,000. The amount awarded to Mr. Straehla for 2017 consists of a cash bonus of $400,000.
(2) The amounts shown reflect the grant date fair value of restricted stock units granted determined in accordance with FASB ASC Topic 718. See Note 13 to our consolidated financial statements included elsewhere in this report. Details regarding equity awards that are still outstanding can be found in the "Outstanding Equity Awards at Fiscal 2017 Year End" table.
(3) Consists of $27,264 attributable to sporting event tickets.

OUTSTANDING EQUITY AWARDS AT FISCAL 2017 YEAR-END

The following table provides information concerning equity awards outstanding for our principal executive officer and our principal financial officer at December 31, 2017. During 2017, we did not have any other executive officers or persons performing similar functions.

Name and Principal Position	Grant Date	Share Price At Grant Date ($)	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares of Stock That Have Not Vested[1] ($)
Arty Straehla, Chief Executive Officer[2]	10/19/2016	$ 15.00	166,667	$ 3,271,673
Mark Layton, Chief Financial Officer[3]	10/19/2016	$ 15.00	11,250	$ 220,838
	2/21/2017	$ 21.18	40,000	$ 785,200

(1) Market value of shares or units that have not vested is based on the closing price of $19.63 per share of our common stock on The Nasdaq Global Select Market on December 29, 2017, the last trading day of 2017.
(2) These restricted stock units vest in two remaining approximately equal annual installments beginning on October 19, 2018.
(3) Restricted stock units granted on October 19, 2016 vest in three remaining approximately equal annual installments beginning on October 19, 2018. Restricted stock units granted on February 21, 2017 vest in three approximately equal annual installments beginning on February 21, 2018.

2017 DIRECTOR COMPENSATION

The following table contains information with respect to 2017 compensation of our directors who served in such capacity during that year, except that the 2017 compensation of the director who is also our named principal executive officer is disclosed in the 2016 and 2017 Summary Compensation Table above.

Name	Board & Committee Retainer Fees	Meeting Fees	Stock Awards[1] ($)	All Other Compensation ($)	Total ($)
Marc McCarthy[2]	$ 20,417	$ 4,500	$ —	$ —	$ 24,917
Paul Heerwagen[3]	$ 10,417	$ 10,000	$ —	$ —	$ 20,417
Arthur Smith	$ 22,917	$ 21,500	$ —	$ —	$ 44,417
André Weiss	$ 6,250	$ 25,500	$ —	$ —	$ 31,750
Matthew Ross	$ 20,417	$ 28,500	$ —	$ —	$ 48,917
James Palm	$ 31,966	$ 4,000	$ —	$ —	$ 35,966

(1) As of December 31, 2017, Messrs. McCarthy, Heerwagen, Smith and Ross each had unvested awards of 2,222 restricted stock units outstanding, which will vest on October 19, 2018. Mr. Weiss forfeited 4,444 unvested awards of restricted stock units granted to him in connection with our IPO in October 2016 upon his resignation from our board of directors in June 2017. The Stock Awards column excludes 2,913, 2,913, 2,913, 2,913 and 4,370 restricted stock units granted to Mr. McCarthy, Mr. Heerwagen, Mr. Smith, Mr. Ross and Mr. Palm, respectively, on February 2, 2018, with a value of $63,562 in the case of each of Mr. McCarthy, Mr. Heerwargen, Mr. Smith and Mr. Ross and $95,343 in the case of Mr. Palm (based on the closing price per share of our common stock of $21.82 on February 2, 2018). These February 2018 grants were made to transition the grant date for the annual equity awards for our non-employee directors from the anniversary date of our IPO to the date of our annual meeting of stockholders and cover the partial service period beginning on October 20, 2017 and ending on June 8, 2018 for each such director, except Mr. Palm, who received his grant for the service period beginning on June 26, 2017, the date he joined our board of directors,

and ending on June 8, 2018. These restricted stock units vest on the earlier of June 8, 2018 or the date of our 2018 Annual Meeting of Stockholders.

(2) As required under the terms of his employment with Wexford, Mr. McCarthy's restricted stock units earned in his capacity as a member of our board of directors were assigned to Wexford.

(3) As required under the terms of his employment with Gulfport, Mr. Heerwagen's restricted stock units earned in his capacity as a member of our board of directors were assigned to Gulfport.

Director Compensation

From the completion of our IPO until December 31, 2017, our non-employee directors were entitled to receive an annual retainer in the amount of $47,500, plus an additional annual payment of $15,000 for the chairperson and $10,000 for each other member of the Audit Committee and $10,000 for the chairperson and $5,000 for each other member of each other committee, with such amounts to be paid in quarterly installments. Additionally, our non-employee directors were entitled to receive $1,000 for each meeting of the board of directors or any of its committees attended in person and $500 for each meeting of the board of directors or any of its committees attended telephonically. Members of our board of directors who are also officers or employees of our company did not receive compensation for their services as directors. We also have provided our non-employee directors with equity compensation under our Equity Incentive Plan as additional compensation and incentive. Effective January 1, 2018, our director compensation program was amended to eliminate meeting fees for the members of our board of directors and its committees and increase the annual retainer amount to $60,000. In addition, the fees payable to the chairperson and each other member of the Audit Committee were increased to $20,000 and $15,000, respectively, and the fees payable to the chairperson and each other member of the Compensation Committee were increased to $15,000 and $10,000, respectively. On the date of each annual meeting of stockholders, our non-employee directors will also receive an annual equity award with a value of $100,000 that will vest on the earlier of the first anniversary of the grant date or the next annual meeting of stockholders.

Compensation Committee Interlocks and Insider Participation

No current member of our Compensation Committee has ever been an officer or employee of ours. However, Mr. McCarthy served as an executive officer of the general partner of Mammoth Partners prior to our IPO in October 2016 and Mr. Heerwagen served as an executive officer of the Stingray entities prior to our acquisition of them in 2014. None of our executive officers serves, or has served during the past fiscal year, as a member of the board of directors or compensation committee of any other company that has one or more executive officers serving as member of our board of directors or compensation committee.

Report of the Compensation Committee on Executive Compensation

The compensation committee has reviewed and discussed the foregoing summary of Executive Compensation with management. Based on its review and discussion with management, the compensation committee recommended that the summary of Executive Compensation be included in this annual report.

Respectfully submitted by the compensation committee:

Marc McCarthy, Chairman
Paul Heerwagen
Arthur Smith
James Palm

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

Holdings of Major Stockholder

The following table sets forth certain information regarding the beneficial ownership as of February 10, 2018 of shares of our common stock by each person or entity known to us to be a beneficial owner of 5% or more of our common stock.

MAJOR STOCKHOLDER TABLE

Name and Address of Beneficial Owner[1]	Amount and Nature of Beneficial Ownership	Percent of Class
Mammoth Energy Holdings LLC c/o Wexford Capital LP 411 West Putnam Avenue Greenwich, CT 06830	25,013,764 [2]	56.1%
Gulfport Energy Corporation 3001 Quail Springs Parkway Oklahoma City, OK 73134	11,176,332 [3]	25.1%
Janus Henderson Group PLC 201 Bishopsgate EC2M 3AE United Kingdom	2,528,488[4]	5.7%

(1) Beneficial ownership is determined in accordance with SEC rules. The percentage of shares beneficially owned is based on 44,589,306 shares of common stock outstanding as of February 10, 2018.

(2) Based solely on Schedule 13G/A filed jointly with the SEC on February 14, 2018 by MEH Sub LLC ("MEH"), Wexford Capital, Wexford GP LLC ("Wexford GP"), Charles E. Davidson ("Mr. Davidson") and Joseph M. Jacobs ("Mr. Jacobs"). MEH is a company managed by Wexford. Wexford is an investment advisor registered with the SEC which manages MEH. Wexford GP is the general partner of Wexford. Mr. Davidson and Mr. Jacobs are the managing members of Wexford GP. MEH has shared voting and dispositive power over 25,009,319 shares of common stock. Wexford, Wexford GP, Mr. Davidson and Mr. Jacobs have shared voting and dispositive power over 25,013,764 shares of common stock. Wexford may, by reason of its status as manager of MEH, be deemed to own beneficially the securities of which MEH possesses beneficial ownership. Wexford GP may, as the General Partner of Wexford, be deemed to own beneficially the securities of which MEH possesses beneficial ownership. Each of Mr. Davidson and Mr. Jacobs may, by reason of his status as a controlling person of Wexford GP, be deemed to own beneficially the securities of which MEH possess beneficial ownership. Each of Wexford, Wexford GP, Davidson and Jacobs share the power to vote and to dispose of the securities beneficially owned by MEH. Each of Wexford, Wexford GP, Mr. Davidson and Mr. Jacobs disclaim beneficial ownership of the securities owned by MEH except, in the case of Mr. Davidson and Mr. Jacobs, to the extent of their respective interests in the members of MEH.

(3) Based solely on Schedule 13D filed with the SEC on February 14, 2018 by Gulfport, in which it reported sole voting and dispositive power of such shares of common stock.

(4) Based solely on Schedule 13G filed with the SEC on February 13, 2018 by Janus Henderson Group PLC, or Janus Henderson. Janus Henderson reported shared voting power and shared dispositive power over 2,528,488 shares of common stock. Janus Henderson has an indirect 97.11% ownership stake in Intech Investment Management LLC ("Intech") and a 100% ownership stake in Janus Capital Management LLC ("Janus Capital"), Perkins Investment Management LLC ("Perkins"), Geneva Capital Management LLC ("Geneva"), Henderson Global Investors Limited ("HGIL"), Janus Henderson Investors Australia Institutional Funds Management Limited ("HGIAIFML") and Henderson Global Investors North America Inc ("HGINA"), (each an "Asset Manager" and collectively as the "Asset Managers"). Due to the above ownership structure, holdings for the Asset Managers are aggregated for purposes of this table. Each Asset Manager is an investment adviser registered or authorized in its relevant jurisdiction and each furnishing investment advice to various fund, individual and/or institutional clients (collectively referred to herein as "Managed Portfolios"). As a result of its role as investment adviser or sub-adviser to the Managed Portfolios, Janus Capital may be deemed to be the beneficial owner of 19,400 shares or 0.0% of the shares of outstanding common stock. Janus Capital disclaims any ownership associated with such rights. As a result of its role as investment adviser or sub-adviser to the Managed Portfolios, Perkins may be deemed to be the beneficial owner of 2,509,088 shares or 5.6% of the shares of outstanding common stock. Perkins disclaims any ownership associated with such rights.

Holdings of Officers and Directors

The following table sets forth certain information regarding the beneficial ownership as of February 10, 2018 of shares of our common stock by each of our directors, by each named executive officer and by all directors and executive officers as a group:

Name of Beneficial Owner[(1)]	Amount and Nature of Beneficial Ownership	Percent of Class
Marc McCarthy[(2)]	—	*
Arty Straehla[(3)]	59,283	*
Paul Heerwagen[(4)]	—	*
Arthur Smith[(5)]	10,445	*
Matthew Ross[(6)]	4,445	*
James Palm[(7)]	12,700	*
Mark Layton[(8)]	19,159	*
Directors and Executive Officers as a Group (7 persons)	106,032	*

*Less than 1%

(1) Beneficial ownership is determined in accordance with SEC rules. In computing percentage ownership of each person, shares of common stock subject to any options or restricted stock units held by that person that are exercisable or vested as of February 10, 2018, or exercisable or vesting within 60 days of February 10, 2018, are deemed to be beneficially owned. These shares, however, are not deemed outstanding for the purpose of computing the percentage ownership of each other person. The percentage of shares beneficially owned is based on 44,589,306 shares of common stock outstanding as of February 10, 2018. Unless otherwise indicated, all amounts exclude shares issuable upon the exercise of outstanding options and the vesting of restricted stock units that are not exercisable and/or vested as of February 10, 2018 or within 60 days of February 10, 2018.

(2) Excludes (i) 4,445 shares of common stock, (ii) 2,222 restricted stock units granted under our equity incentive plan, which will vest on October 19, 2018 and (iii) 2,913 restricted stock units granted under our equity incentive plan, which will vest on the earlier of June 8, 2018 and the date of the 2018 annual meeting, all of which were assigned to Wexford under the terms of Mr. McCarthy's employment with Wexford. As a result, Mr. McCarthy disclaims beneficial ownership of these shares of common stock and restricted stock units, except to the extent of any pecuniary interest therein.

(3) 1,792 of these securities are held in three custodial accounts for the benefit of three of Mr. Straehla's grandchildren and for which Mr. Straehla maintains investment control. Excludes 166,667 restricted stock units granted under our equity incentive plan, which will vest in two approximately equal annual installments beginning on October 19, 2018.

(4) Excludes (i) 2,222 shares of common stock, (ii) 2,222 restricted stock units granted to under our equity incentive plan, which will vest on October 19, 2018 and (iii) 2,913 restricted stock units granted under our equity incentive plan, which will vest on the earlier of June 8, 2018 and the date of the 2018 annual meeting, all of which were assigned to Gulfport under the terms of Mr. Heerwagen's employment with Gulfport. As a result, Mr. Heerwagen disclaims beneficial ownership of these shares of common stock and restricted stock units.

(5) Excludes (i) 2,222 restricted stock units granted under our equity incentive plan, which will vest on October 19, 2018, and (ii) 2,913 restricted stock units granted under our equity incentive plan, which will vest on the earlier of June 8, 2018 and the date of the 2018 annual meeting. Includes 6,000 shares of common stock held by Arthur L. Smith Family LP, which is managed by Arthur L. Smith Management LLC, of which Mr. Smith is the manager.

(6) Excludes (i) 2,222 restricted stock units granted under our equity incentive plan, which will vest on October 19, 2018, and (ii) 2,913 restricted stock units granted under our equity incentive plan, which will vest on the earlier of June 8, 2018 and the date of the 2018 annual meeting.

(7) Excludes 4,370 restricted stock units granted under our equity incentive plan, which will vest on the earlier of June 8, 2018 and the date of the 2018 annual meeting.

(8) Excludes (i) 11,250 restricted stock units granted under our equity incentive plan, which will vest in three approximately equal annual installments beginning on October 19, 2018, and (ii) 26,666 restricted stock units granted under our equity incentive plan, which will vest in two remaining approximately equal annual installments beginning on February 21, 2019.

Item 13. Certain Relationships and Related Transactions and Director Independence

Certain Relationships and Related Transactions

Review and Approval of Related Party Transactions

The Audit Committee, as provided in its charter, reviews and approves related party transactions. The Company does not have a formal set of standards to be substantively applied to each transaction reviewed by the Audit Committee. Instead of a formalized policy, related party transactions are reviewed and judgment is applied to determine whether such transactions are in the best interests of the Company. Further, the Company's Code of Business Conduct and Ethics governs various compliance areas, including conflicts of interest and fair dealings, which are considered in the process of the review and approval of related party transactions.

The Company’s policy is that all of its employees and directors, as well as their family members, must avoid any activity that is or has the appearance of conflicting with the Company’s business interest. This policy is included in the Company’s Code of Business Conduct and Ethics posted on its website. Each director and executive officer is instructed to always inform the designated compliance officer when confronted with any situation that may be perceived as a conflict of interest. Only the board of directors or a committee consisting solely of independent directors may grant waivers of the provisions of the Code of Business Conduct and Ethics for the Company’s executive officers and directors. In addition, at least annually, each director and executive officer completes a detailed questionnaire specifying any business relationship that may give rise to a conflict of interest.

Further, under the Audit Committee Charter, the Audit Committee is responsible for reviewing and monitoring compliance with our Code of Business Conduct and Ethics and recommending any warranted changes to the board of directors. In addition, the board of directors and, pursuant to its written charter, the Audit Committee, reviews and approves all relationships and transactions in which the Company and its directors, director nominees and executive officers and their immediate family members, as well as holders of more than 5% of any class of our voting securities and their family members, have a direct or indirect material interest. The board of directors and the Audit Committee approve only those transactions that, in light of known circumstances, are consistent, or are not inconsistent with, the Company’s best interests, as they determine in the good faith exercise of their discretion.

Registration Rights and Investor Rights Agreements

In connection with the closing of our IPO on October 19, 2016, we entered into two registration rights agreements, one with Mammoth Holdings and the other with Rhino Exploration LLC, or Rhino, pursuant to which Mammoth Holdings and its affiliates have certain demand and “piggyback” registration rights and Rhino has certain “piggyback” registration rights. Further, in connection with our IPO on October 19, 2016, we entered into an investor rights agreement with Gulfport in which Gulfport was granted certain demand and “piggyback” registration rights. Gulfport was also granted certain information rights and the right to nominate one of our directors for so long as Gulfport owns 10% or more of our outstanding common stock. Such nominee, if elected to our board of directors, will also serve on each committee of the board of directors so long as he or she satisfies the independence and other requirements for service on the applicable committee. So long as Gulfport has the right to designate a nominee to our board of directors and there is no Gulfport nominee actually serving as our director, Gulfport will have the right to appoint one individual as an advisor to the board of directors who shall be entitled to attend board and committee meetings. One of our directors, Mr. Heerwagen, was nominated by Gulfport pursuant to the investor rights agreement and elected by our stockholders at the 2017 Annual Meeting of Stockholders to serve until the next annual meeting of our stockholders or until his earlier death, resignation or removal.

Contribution Agreements

On March 20, 2017, as amended and restated on May 12, 2017, we entered into three definitive contribution agreements, one with MEH, Wexford Offshore Sturgeon Corp. (each an affiliate of Wexford), Gulfport, Rhino and Mammoth Energy Partners LLC, referred to as Mammoth Partners LLC, one with MEH Sub, Wexford Offshore Stingray Energy Corp., Gulfport and Mammoth LLC, and the other with MEH, Wexford Offshore Stingray Pressure Pumping Corp., Gulfport and Mammoth LLC, which we collectively refer to as the Contribution Agreements. Under the Contribution Agreements, we agreed to acquire all outstanding membership interests in Sturgeon Acquisitions LLC, or Sturgeon (which owns Taylor Frac, LLC, Taylor Real Estate Investments, LLC and South River Road, LLC, which are collectively referred to as Taylor Frac), Stingray Energy Services LLC, or Stingray Energy, and Stingray Cementing LLC, or Stingray Cementing, respectively, for an aggregate of 7.0 million shares of our common stock valued at approximately $129.5 million based on the closing price of $18.50 per share for our common stock on June 5, 2017. These transactions were completed on June 5, 2017. Taylor Frac owns a sand mine and processing plant. Stingray Energy and Stingray Cementing, combined, offer services in fresh water transfer, equipment rental, re-fueling as well as cementing and operate primarily in the Appalachian basin. We have provided certain management, administrative and treasury functions to Taylor Frac, Stingray Energy and Stingray Cementing since 2014. Prior to our June 5, 2017 acquisition of Taylor Frac in our Sturgeon acquisition, we and Sturgeon were under common control and, as a result, our historical financial information for all periods included in this Annual Report on Form 10-K has been recast to combine Sturgeon's financial results with our financial results as if the acquisition had been effective since Sturgeon commenced operations in September 2014.

As of December 31, 2017, Wexford beneficially owned approximately 56.1% of our outstanding common stock. Our Chairman of the Board currently serves as a Partner at Wexford. As of December 31, 2017, Gulfport beneficially owned approximately 25.1% of our outstanding common stock. Mr. Heerwagen, one of our directors, is Gulfport’s designee to our board of directors under the investor rights agreement described under “-Registration Rights and Investor Rights Agreements” above. The shares of our common stock issued to MEH, Gulfport and Rhino under the Contribution Agreements are subject to the registration rights described under "-Registration Rights and Investor Rights Agreements" above.

A special committee of our board of directors, comprised entirely of independent directors, reviewed and unanimously recommended the transactions contemplated by the contribution agreements to our board. Evercore Group L.L.C. served as financial advisor to the special committee, and Kramer Levin Naftalis & Frankel LLP served as legal counsel to the special committee.

Advisory Services Agreement

We are party to an advisory services agreement with Wexford under which Wexford provides us with general financial and strategic advisory services related to our business in return for an annual fee of $500,000, plus reasonable out-of-pocket expenses. This agreement has a term of two years commencing on the completion of our IPO. The agreement will continue for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. The agreement may be terminated at any time by either party upon 30 days' prior written notice. In the event we terminate the agreement, we are obligated to pay all amounts due through the remaining term of the agreement. In addition, in this agreement we have agreed to pay Wexford to-be-negotiated market-based fees approved by our independent directors for such services as may be provided by Wexford at our request in connection with future acquisitions and divestitures, financings or other transactions in which we may be involved. The services provided by Wexford under the advisory services agreement do not extend to our day-to-day business or operations. In this agreement, we have agreed to indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the agreement except for losses resulting from Wexford's or its affiliates' gross negligence or willful misconduct. In the event we are dissatisfied with the services provided by Wexford, our only remedy against Wexford will be to terminate the agreement. For the year ended December 31, 2017, we paid Wexford $0.5 million under this advisory services agreement.

Other Agreements with Affiliates

Services and Products We Provide to Affiliates

In September 2014, effective October 1, 2014, Gulfport entered into an amended and restated master services agreement with Pressure Pumping for pressure pumping services. Pursuant to this agreement, Pressure Pumping has agreed to provide pressure pumping, stimulation and related completion and rework services to Gulfport, dedicating two spreads and related equipment for the performance of these services. Gulfport has agreed to pay Pressure Pumping a monthly service fee plus the associated costs of the services provided. Gulfport and Pressure Pumping have each agreed to maintain insurance at certain minimum thresholds. This agreement has a term of four years ending on September 30, 2018 and includes, among others, confidentiality and non-solicitation provisions. This agreement may be terminated in the event of a covenant breach by either party on 45 days written notice and a failure to cure. Pressure Pumping may also terminate in the event of payment default by Gulfport. Additionally, Gulfport can, without liability, countermand any work order given to us at any time before we begin such work. If the work had already begun, Gulfport could then still cancel the service at any time, being liable only for the value of the work performed prior to the cancellation. We can terminate the master service agreement by giving Gulfport written notice prior to receiving a notification from Gulfport to perform a specific service. For the year ended December 31, 2017, we recognized revenue from Gulfport of approximately $144.5 million and, as of December 31, 2017, Gulfport owed us approximately $25.1 million for such services.

In September 2014, effective October 1, 2014, Gulfport entered into a sand supply agreement, as amended on November 3, 2015, with Muskie Proppant. Pursuant to this agreement, Muskie Proppant has agreed to sell and deliver, and Gulfport has agreed to purchase, specified annual and monthly amounts of proppant sand, subject to certain exceptions specified in the agreement, and pay certain costs and expenses. Failure by either Muskie Proppant or Gulfport to deliver or accept the minimum monthly amount results in damages calculated per ton based on the difference between the monthly obligation amount and the amount actually delivered or accepted, as applicable. In addition, failure to pick up the sand on a timely basis from the designated facility will lead to demurrage charges payable by Gulfport. If Gulfport fails to make payments when due, or Muskie Proppant fails to deliver the required amounts of sand over three consecutive months, the other party can terminate the sand supply agreement. The sand supply agreement has a term ending on September 30, 2018 and includes, among others, confidentiality and non-solicitation provisions. For the year ended December 31, 2017, we recognized revenue from Gulfport of approximately $43.0 million and, as of December 31, 2017, Gulfport owed us approximately $1.9 million for such services.

Our wholly owned subsidiaries, Stingray Energy, Stingray Cementing and Panther Drilling provide services to Gulfport pursuant to master service agreements. These master service agreements may be terminated by us at any time prior to the receipt of notification by Gulfport to perform work pursuant to the agreements. Gulfport may terminate the master service agreements at any time by giving us written notice. The master service agreements do not obligate Gulfport to call upon us to perform any work under the master service agreements, and we are not obligated to accept any work requests from Gulfport. The designation of any work to be performed by us and the cessation of such work is at the sole discretion of Gulfport. For the year ended December 31, 2017, Stingray Energy recognized revenue of approximately $10.1 million for services performed for Gulfport and, as of December 31, 2017, Gulfport owed Stingray Energy $3.3 million for such services. For the year ended December 31, 2017, Stingray Cementing recognized revenue of approximately $7.4 million for services performed for Gulfport and, as of December 31, 2017, Gulfport owed Stingray Cementing $2.3 million for such services. For the year ended December 31, 2017, Panther Drilling recognized revenue of approximately $3.3 million for services performed for Gulfport and, as of December 31, 2017, Gulfport owed Panther Drilling $0.9 million for such services.

Our contract land and directional drilling services segment leases equipment to Predator Drilling LLC, or Predator, an entity in which Wexford owns a minority interest. For the year ended December 31, 2017 we recognized revenue of $0.2 million and, as of December 31, 2017, Predator owed us $0.2 million for such services.

Our contract land and directional drilling services segment performs various services for El Toro Resources LLC, or El Toro, an affiliate of Wexford, pursuant to a master service agreement dated February 22, 2013. For the year ended December 31, 2017 we recognized revenue of $0.1 million and, as of December 31, 2017, there were no receivables outstanding.

Our wholly owned subsidiaries, Redback Coil Tubing and Redback Energy Services, provide rental services to El Toro pursuant to a master service agreement dated February 22, 2013. For the year ended December 31, 2017, we recognized revenue of $0.4 million and, as of December 31, 2017, there were no receivables outstanding.

Our contract land and directional drilling services segment provides rental services to Double Barrel Downhole Technologies, LLC, or DBDHT, an affiliate of Wexford. For the year ended December 31, 2017, we recognized revenue of $27,133 and, as of December 31, 2017, we were owed $9,515 for such services.

We provide remote accommodation and food services to Grizzly Oil Sands ULC, or Grizzly, an entity owned approximately 75% by affiliates of Wexford and approximately 25% by Gulfport. Since June 25, 2012, these services have been provided to Grizzly pursuant to a written agreement with an initial term of one year. The agreement automatically renews for successive one-year terms unless terminated by either party by giving written notice of such termination to the other party at least 30 days prior to the expiration of the then-current term. For the year ended December 31, 2017, we recognized revenue from Grizzly of approximately $1,586 and, as of December 31, 2017, Grizzly owed us approximately $1,264 for such services.

Prior to the acquisition of Stingray Energy and Stingray Cementing, we provided certain management, administrative and treasury functions to these companies. For the year ended December 31, 2017, we recognized revenue of approximately $0.1 million for such services.

We provide certain administrative functions to Dunvegan North Oilfield Services ULC, or Dunvegan, an affiliate of Wexford, DBDHT and El Toro. As of December 31, 2017, we were owed $0.1 million for such services.

Services and Products Our Affiliates Provide to Us

T&E Flow Services LLC, or T&E, provides products and services to our infrastructure businesses. Our Chief Executive Officer's son has a 25% ownership interest in T&E. For the year ended December 31, 2017, we incurred total costs from T&E of $2.6 million, of which $2.0 million were capitalized. As of December 31, 2017, we owed T&E approximately $0.9 million.

Everest Operations Management LLC, or Everest, a subsidiary of Wexford, has historically provided certain technical, administrative and payroll services to us, and we have reimbursed Everest in amounts determined by it based on estimates of the amount of employees' time spent performing services for us. The reimbursement amounts were determined based upon underlying salary costs of employees performing company-related functions, payroll, revenue or headcount relative to other companies managed by Everest, or specifically identified invoices processed, depending on the nature of the cost. Additionally, from time to time, we pay for goods and services on behalf of Everest. For the year ended December 31, 2017, we incurred total costs under these arrangements of $0.2 million and, as of December 31, 2017, owed approximately $19,015.

Wexford provides certain administrative and analytical services to us and, from time to time, we pay for goods and services on behalf of Wexford. For the year ended December 31, 2017, we incurred total costs under these arrangements of $0.9 million and, as of December 31, 2017, owed approximately $0.1 million.

Stingray Energy rents equipment and paid for goods and services on our behalf. Prior to our acquisition of Stingray Energy in June 2017, we incurred total costs under these arrangements of $0.4 million.

Panther Drilling rents rotary steerable equipment in connection with its directional drilling services from DBDHT, an affiliate of Wexford. For the year ended December 31, 2017, we incurred total costs under these arrangements of $0.2 million and, as of December 31, 2017, owed approximately $0.1 million.

Redback Energy Services leases property from Elk City Yard, LLC, an affiliate of Wexford. During the year ended December 31, 2017, Redback Energy Services incurred costs of $0.1 million. There were no amounts owed under this agreement as of December 31, 2017. The lease extends until 2022 at a rental rate of approximately $0.1 million per year.

Mammoth entered into a five-year office space lease with Caliber Investment Group LLC, or Caliber, in May 2017. During the year ended December 31, 2017, Mammoth incurred costs of $0.3 million related to this lease. This lease extends through April 2022 at a rental rate of approximately $0.5 million per year. Caliber is an affiliate of Wexford.

Dunvegan provides technical and administrative services and pays for goods and services on our behalf. For the year ended December 31, 2017, we incurred total costs under these arrangements of $5,900. There were no amounts owed under this agreement as of December 31, 2017.

Stingray Energy entered into a 12-month equipment yard lease with Caliber, an affiliate of Wexford, beginning in February 2018. This lease extends through January 2019 at a rental rate of $8,000 per month.

Item 14. Principal Accountant Fees and Services

Grant Thornton's fees for professional services totaled $1.4 million for 2017 and $1.2 million for 2016. Grant Thornton's fees for professional services included the following:

- Audit Fees - aggregate fees for audit services, which relate to the fiscal year consolidated audit and quarterly reviews, were $1.1 million in 2017 and $1.0 million in 2016.
- Audit-Related Fees - aggregate fees for audit-related services, which relate to registration statements and comfort letters, were $0.3 million in 2017 and $0.5 million in 2016.
- Tax Fees- aggregate fees for tax services, consisting of tax return compliance, tax advice and tax planning, were zero in 2017 and $5,000 in 2016.
- All Other Fees - aggregate fees for all other services, were zero in 2017 and 2016.

It is our audit committee's policy to pre-approve all audit, audit related and permissible non-audit services rendered to us by our independent auditor. Consistent with such policy, all of the fees listed above that we incurred for services rendered by Grant Thornton LLP subsequent to our IPO in October 2016 and the formation of our audit committee were pre-approved by our audit committee.

PART IV.

Item 15. Exhibits, Financial Statement Schedules

The following documents are filed as part of this report or incorporated by reference herein:

(1) *Financial Statements*

(2) *Financial Statement Schedules*

All financial statement schedules have been omitted because they are not applicable or the required disclosure is presented in the financial statements or notes thereto.

(3) *Exhibits*

Exhibit Number	Exhibit Description
2.1#	Amended and Restated Contribution Agreement by and among MEH Sub LLC, Gulfport Energy Corporation, Rhino Exploration LLC, Mammoth Energy Partners LLC and Mammoth Energy Services, Inc. dated as of May 12, 2017 (incorporated by reference to Exhibit A-1 to the Company's Definitive Schedule 14C, filed with the SEC on May 15, 2017).
2.2#	Amended and Restated Contribution Agreement by and among MEH Sub LLC, Gulfport Energy Corporation, Mammoth Energy Partners LLC and Mammoth Energy Services, Inc. dated as of May 12, 2017 (incorporated by reference to Exhibit A-2 to the Company's Definitive Schedule 14C, filed with the SEC on May 15, 2017).
2.3#	Amended and Restated Contribution Agreement by and among MEH Sub LLC, Gulfport Energy Corporation, Mammoth Energy Partners LLC and Mammoth Energy Services, Inc. dated as of May 12, 2017 (incorporated by reference to Exhibit A-3 to the Company's Definitive Schedule 14C, filed with the SEC on May 15, 2017).
2.4#	Purchase and Sale Agreement, dated as of March 27, 2017, by and between Mammoth Energy Services, Inc., as purchaser, and Chieftain Sand and Proppant, LLC and Chieftain Sand and Proppant Barron, LLC, as sellers (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on May 15, 2017).
3.1	Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on November 15, 2016).
3.2	Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on November 15, 2016).
4.1	Specimen Certificate for shares of common stock, par value $0.01 per share, of the Company (incorporated by reference to Exhibit 4.1 to the Company's Amendment No. 2 to the Registration Statement on Form S-1/A (File No. 333-213504), filed with the SEC on October 3, 2016).
4.2	Registration Rights Agreement, dated October 12, 2016, by and between the Company and Mammoth Energy Holdings, LLC (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on November 15, 2016).
4.3	Investor Rights Agreement, dated October 12, 2016, by and between the Company and Gulfport Energy Corporation (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on November 15, 2016).
4.4	Registration Rights Agreement, dated October 12, 2016, by and between the Company and Rhino Exploration LLC (incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on November 15, 2016).
10.1	Advisory Services Agreement, dated as of October 19, 2016, by and between the Company and Wexford Capital LP (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on November 15, 2016).
10.2	Master Service Contract, effective May 16, 2013, by and between Muskie Proppant LLC and Diamondback E&P LLC (incorporated by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-1 (File No. 333-213504), filed with the SEC on September 2, 2016).
10.3	Master Service Agreement, dated February 22, 2013, by and between Gulfport Energy Corporation and Panther Drilling Systems LLC (incorporated by reference to Exhibit 10.3 to the Company's Registration Statement on Form S-1 (File No. 333-213504), filed with the SEC on September 2, 2016).
10.4	Amendment to Master Service Agreement, dated as of May 23, 2016, by and among Gulfport Energy Corporation, Gulfport Buckeye LLC and Panther Drilling Systems LLC (incorporated by reference to Exhibit 10.4 to the Company's Registration Statement on Form S-1 (File No. 333-213504), filed with the SEC on September 2, 2016).

10.5	Master Service Contract, effective September 9, 2013, by and between Panther Drilling Systems LLC and Diamondback E&P LLC (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1 (File No. 333-213504), filed with the SEC on September 2, 2016).
10.6	First Amendment, dated February 21, 2013, to Master Field Services Agreement, effective January 1, 2013, by and between Diamondback E&P LLC and Bison Drilling and Field Services LLC (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1 (File No. 333-213504), filed with the SEC on September 2, 2016).
10.7	Master Field Services Agreement, effective January 1, 2013, by and between Diamondback E&P LLC and Bison Drilling and Field Services LLC (incorporated by reference to Exhibit 10.7 to the Company's Registration Statement on Form S-1 (File No. 333-213504), filed with the SEC on September 2, 2016).
10.8	Master Drilling Agreement, effective January 1, 2013, by and between Diamondback E&P LLC and Bison Drilling and Field Services LLC (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1 (File No. 333-213504), filed with the SEC on September 2, 2016).
10.9	Master Service Agreement, dated June 11, 2012, by and between Gulfport Energy Corporation and Redback Energy Services LLC (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1 (File No. 333-213504), filed with the SEC on September 2, 2016).
10.10	Master Service Contract, effective October 17, 2013, by and between Bison Trucking LLC and Diamondback E&P LLC (incorporated by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1 (File No. 333-213504), filed with the SEC on September 2, 2016).
10.11	Mammoth Energy Securities, Inc. 2016 Equity Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on November 15, 2016).
10.12	Form of Option Agreement (incorporated by reference to Exhibit 10.12 to the Company's Amendment No. 1 to the Registration Statement on Form S-1/A (File No. 333-213504), filed with the SEC on September 23, 2016).
10.13	Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.13 to the Company's Amendment No. 1 to the Registration Statement on Form S-1/A (File No. 333-213504), filed with the SEC on September 23, 2016).
10.14†	Form of Director and Officer Indemnification Agreement (incorporated by reference to Exhibit 10.14 to the Company's Amendment No. 2 to the Registration Statement on Form S-1/A (File No. 333-213504), filed with the SEC on October 3, 2016).
10.15##	Amended & Restated Master Services Agreement for Pressure Pumping Services Agreement, effective as of October 1, 2014, by and between Gulfport Energy Corporation and Stingray Pressure Pumping LLC (incorporated by reference to Exhibit 10.15 to the Company's Registration Statement on Form S-1 (File No. 333-213504), filed with the SEC on September 2, 2016).
10.16##	Amendment to Amended and Restated Master Services Agreement, dated as of February 18, 2016 to be effective as of January 1, 2016, by and between Gulfport Energy Corporation and Stingray Pressure Pumping LLC (incorporated by reference to Exhibit 10.16 to the Company's Registration Statement on Form S-1 (File No. 333-213504), filed with the SEC on September 2, 2016).
10.17	Amendment to Master Service Agreement, dated as of July 7, 2016, by and among Gulfport Energy Corporation, Gulfport Buckeye LLC and Stingray Pressure Pumping LLC (incorporated by reference to Exhibit 10.17 to the Company's Registration Statement on Form S-1 (File No. 333-213504), filed with the SEC on September 2, 2016).
10.18##	Sand Supply Agreement, effective as of October 1, 2014, by and between Muskie Proppant LLC and Gulfport Energy Corporation (incorporated by reference to Exhibit 10.18 to the Company's Registration Statement on Form S-1 (File No. 333-213504), filed with the SEC on September 2, 2016).
10.19##	Amendment to Sand Supply Agreement, dated as of November 3, 2015, by and between Muskie Proppant LLC and Gulfport Energy Corporation (incorporated by reference to Exhibit 10.19 to the Company's Registration Statement on Form S-1 (File No. 333-213504), filed with the SEC on September 2, 2016).
10.20	Revolving Credit and Security Agreement, dated as of November 25, 2014, among Mammoth Energy Partners LP, Redback Energy Services LLC, Redback Coil Tubing LLC, Muskie Proppant LLC, Panther Drilling Systems LLC, Bison Drilling and Field Services LLC, Bison Trucking LLC, White Wing Tubular Services LLC, Great White Sand Tiger Lodging Ltd., Stingray Pressure Pumping LLC, Stingray Logistics LLC, collectively as the Borrowers, Mammoth Energy Inc. and Barracuda Logistics LLC, as the applicants, certain lenders from time to time party thereto and PNC Bank, National Association, as agent for the lenders (incorporated by reference to Exhibit 10.20 to the Company's Amendment No. 1 to the Registration Statement on Form S-1/A (File No. 333-213504), filed with the SEC on September 23, 2016).
10.21	Joinder Agreement, dated as of March 31, 2015, by and among Mammoth Energy Partners LP, Redback Energy Services LLC, Redback Coil Tubing LLC, Muskie Proppant LLC, Panther Drilling Systems LLC, Bison Drilling and Field Services LLC, Bison Trucking LLC, White Wing Tubular Services LLC, Great White Sand Tiger Lodging Ltd., Stingray Pressure Pumping LLC, Stingray Logistics LLC, collectively as the Borrowers, Mammoth Energy Inc. and Barracuda Logistics LLC, as the applicants, certain lenders from time to time party thereto and PNC Bank, National Association, as agent for the lenders (incorporated by reference to Exhibit 10.21 to the Company's Amendment No. 1 to the Registration Statement on Form S-1/A (File No. 333-213504), filed with the SEC on September 23, 2016).
10.22	Joinder Agreement, dated as of September 2, 2016, by and among Mammoth Energy Partners LP, Redback Energy Services LLC, Redback Coil Tubing LLC, Muskie Proppant LLC, Panther Drilling Systems LLC, Bison Drilling and Field Services LLC, Bison Trucking LLC, White Wing Tubular Services LLC, Great White Sand Tiger Lodging Ltd., Stingray Pressure Pumping LLC, Stingray Logistics LLC, Mammoth Energy Inc., Barracuda Logistics LLC, collectively as the Borrowers, Silverback Energy Services LLC, as applicant, certain lenders from time to time party thereto and PNC Bank, National Association, as agent for the lenders (incorporated by reference to Exhibit 10.22 to the Company's Amendment No. 1 to the Registration Statement on Form S-1/A (File No. 333-213504), filed with the SEC on September 23, 2016).
10.23	First Amendment to Revolving Credit and Security Agreement, dated as of September 30, 2016 by and among Mammoth Energy Partners LP, Redback Energy Services LLC, Redback Coil Tubing LLC, Muskie Proppant LLC, Panther Drilling Systems LLC, Bison Drilling And Field Services LLC, Bison Trucking LLC, White Wing Tubular Services LLC, Great White Sand Tiger Lodging LTD., Stingray Pressure Pumping LLC, Stingray Logistics LLC, Mammoth Energy Inc., Barracuda Logistics LLC and Silverback Energy Services LLC, collectively as existing borrowers, Mammoth Energy Services Inc., Redback Pumpdown Services LLC, Mr. Inspections LLC and Sand Tiger Holdings Inc., as new borrowers, the lenders party to the Credit Agreement from time to time, and PNC Bank, National Association, as a lender and agent for the lenders (incorporated by reference to Exhibit 10.23 to the Company's Amendment No. 2 to the Registration Statement on Form S-1/A (File No. 333-213504), filed with the SEC on October 3, 2016).
10.24	Second Amendment to Revolving Credit and Security Agreement, dated as of July 12, 2017 among Mammoth Energy Services, Inc. and its subsidiaries (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (File No. 001-37917), filed with the SEC on August 4, 2017).
10.25	Emergency Master Service Agreement for PREPA's Electrical Grid Repairs-Hurricane Maria, executed on October 19, 2017, by the Puerto Rico Electric Power Authority (PREPA) and Cobra Acquisitions LLC (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (File No. 001-37917), filed with the SEC on November 14, 2017).

10.26	Amendment No. 1 to Emergency Master Service Agreement for PREPA's Electrical Grid Repairs-Hurricane Maria, executed on November 1, 2017, by the Puerto Rico Electric Power Authority (PREPA) and Cobra Acquisitions LLC (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (File No. 001-37917), filed with the SEC on November 14, 2017).
10.27	Amendment No. 2 to Emergency Master Service Agreement for PREPA's Electrical Grid Repairs-Hurricane Maria, dated as of December 8, 2017, between the Puerto Rico Electric Power Authority (PREPA) and Cobra Acquisitions LLC (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on January 31, 2018).
10.28	Amendment No. 3 to Emergency Master Service Agreement for PREPA's Electrical Grid Repairs-Hurricane Maria, dated December 21, 2017, between the Puerto Rico Electric Power Authority (PREPA) and Cobra Acquisitions LLC (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on January 31, 2018).
10.29	Amendment No. 4 to Emergency Master Service Agreement for PREPA's Electrical Grid Repairs-Hurricane Maria, dated as of January 28, 2018, between the Puerto Rico Electric Power Authority (PREPA) and Cobra Acquisitions LLC (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (File No. 001-37917), filed with the SEC on January 31, 2018).
10.30	Office Lease Agreement, dated as of March 31, 2017, by and between the Company and Caliber Investment Group LLC (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (File No. 001-37917), filed with the SEC on May 15, 2017).
10.31*	Master Subcontract Agreement, dated as of November 2, 2017, by and among Cobra Acquisitions LLC and T&E Flow Services LLC.
10.32*	Equipment Lease Agreement, dated as of August 1, 2017, by and among Bison Drilling and Field Services LLC and Predator Drilling LLC.
10.33*	Equipment Lease Agreement, dated as of August 15, 2017, by and among Bison Drilling and Field Services LLC and Predator Drilling LLC.
10.34*	Amendment No. 5 to Emergency Master Service Agreement for PREPA's Electrical Grid Repairs-Hurricane Maria, dated as of February 27, 2018, between the Puerto Rico Electric Power Authority (PREPA) and Cobra Acquisitions LLC.
21.1*	List of Significant Subsidiaries of the Company.
23.1*	John T. Boyd Company Consent.
23.2*	Consent of Grant Thornton LLP with respect to the financial statements of Mammoth Energy Services Inc.
23.3*	Consent of PricewaterhouseCoopers LLP with respect to the financial statements of Sturgeon Acquisitions LLC.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2**	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
95.1*	Mine Safety Disclosure Exhibit.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith.

** Furnished herewith, not filed.

\+ Management contract, compensatory plan or arrangement.

\# The schedules (or similar attachments) referenced in this agreement have been omitted in accordance with Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule (or similar attachment) will be furnished supplementally to the Securities and Exchange Commission.

\## Confidential treatment with respect to certain portions of this agreement was granted by the SEC which portions have been omitted and filed separately with the SEC.

Item 16. Form 10-K Summary

None.

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

			MAMMOTH ENERGY SERVICES, INC.
Date:	February 28, 2018	By:	/s/ Mark Layton
			Mark Layton
			Chief Financial Officer

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

Signature	Title	Date
/s/ Arty Straehla Arty Straehla	Chief Executive Officer (principal executive officer) and Director	February 28, 2018
/s/ Mark Layton Mark Layton	Chief Financial Officer (principal financial and accounting officer)	February 28, 2018
/s/ Marc McCarthy Marc McCarthy	Director (Chairman of the Board)	February 28, 2018
/s/ Paul K. Heerwagen IV Paul K. Heerwagen IV	Director	February 28, 2018
/s/ Matthew Ross Matthew Ross	Director	February 28, 2018
/s/ Arthur Smith Arthur Smith	Director	February 28, 2018
/s/ James Palm James Palm	Director	February 28, 2018

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Mammoth Energy Services, Inc.

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Mammoth Energy Services, Inc. (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2017 and 2016, and the related consolidated statements of comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2017 and the related notes (collectively referred to as the “financial statements”). In our opinion, based on our audits and the report of the other auditors, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We did not audit the financial statements of Sturgeon Acquisitions LLC, a wholly-owned subsidiary, which statements reflect total assets constituting $84,509,742 of consolidated total assets as of December 31, 2016, and total revenues of $27,473,025 and $31,643,413, respectively, of consolidated total revenues for the years ended December 31, 2016 and 2015. Those statements were audited by other auditors, whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Sturgeon Acquisitions LLC, is based solely on the report of the other auditors.

Basis for opinion
These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Company’s auditor since 2012.

Oklahoma City, Oklahoma
February 28, 2018

Report of Independent Registered Public Accounting Firm

To the Management of Sturgeon Acquisitions LLC

In our opinion, the consolidated balance sheets and the related consolidated statements of net income, of cash flows, and of members' equity (not presented herein) present fairly, in all material respects, the financial position of Sturgeon Acquisitions LLC and its subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
August 14, 2017

MAMMOTH ENERGY SERVICES, INC.

CONSOLIDATED BALANCE SHEETS

ASSETS	December 31, 2017	December 31, 2016 (a)
	(in thousands)	
CURRENT ASSETS		
Cash and cash equivalents	$ 5,637	$ 29,239
Accounts receivable, net	243,746	21,169
Receivables from related parties	33,788	27,589
Inventories	17,814	6,124
Prepaid Expenses	12,552	4,426
Other current assets	886	392
Total current assets	314,423	88,939
Property, plant and equipment, net	351,017	242,120
Sand reserves	74,769	55,367
Intangible assets, net - customer relationships	9,623	15,950
Intangible assets, net - trade names	6,516	5,617
Goodwill	99,811	88,727
Deferred income tax asset	6,739	—
Other non-current assets	4,345	5,642
Total assets	$ 867,243	$ 502,362
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 141,306	$ 20,469
Payables to related parties	1,378	203
Accrued expenses and other current liabilities	40,895	8,546
Income taxes payable	36,409	28
Total current liabilities	219,988	29,246
Long-term debt	99,900	—
Deferred income taxes	34,147	47,671
Asset retirement obligations	2,123	260
Other liabilities	3,289	2,404
Total liabilities	359,447	79,581
COMMITMENTS AND CONTINGENCIES (Note 16)		
EQUITY		
Equity:		
Common stock, $0.01 par value, 200,000,000 shares authorized, 44,589,306 and 37,500,000 issued and outstanding at December 31, 2017 and 2016	446	375
Additional paid in capital	508,010	400,206
Retained earnings (deficit)	2,001	(56,323)
Members' equity	—	81,739
Accumulated other comprehensive loss	(2,661)	(3,216)
Total equity	507,796	422,781
Total liabilities and equity	$ 867,243	$ 502,362

(a) Financial information has been recast to include the financial position and results attributable to Sturgeon Acquisition LLC ("Sturgeon"). See Note 14.

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

MAMMOTH ENERGY SERVICES, INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Years Ended December 31,		
	2017 (a)	2016 (b)	2015 (b)
REVENUE	(in thousands, except per share amounts)		
Services revenue	$ 435,409	$ 89,643	$ 172,012
Services revenue - related parties	166,064	107,147	132,553
Product revenue	47,067	8,052	25,190
Product revenue - related parties	42,956	25,783	38,182
Total revenue	691,496	230,625	367,937
COST AND EXPENSES			
Services cost of revenue (exclusive of depreciation and amortization of $82,686, $65,705 and $68,054, respectively, for 2017, 2016 and 2015)	390,112	140,063	225,944
Services cost of revenue - related parties (exclusive of depreciation and amortization of $0, $0 and $0, respectively, for 2017, 2016 and 2015)	1,408	1,063	1,379
Product cost of revenue (exclusive of depreciation and amortization of $9,389, $6,477 and $6,298, respectively, for 2017, 2016 and 2015)	91,049	31,892	47,364
Product cost of revenue - related parties (exclusive of depreciation and amortization of $0, $0 and $0, respectively, for 2017, 2016 and 2015)	—	3	—
Selling, general and administrative	48,405	17,290	21,449
Selling, general and administrative - related parties	1,481	758	951
Depreciation, depletion, amortization and accretion	92,124	72,315	74,499
Impairment of long-lived assets	4,146	1,871	12,124
Total cost and expenses	628,725	265,255	383,710
Operating income (loss)	62,771	(34,630)	(15,773)
OTHER (EXPENSE) INCOME			
Interest income	—	—	98
Interest expense	(4,310)	(4,096)	(5,465)
Bargain purchase gain	4,012	—	—
Other, net	(677)	158	(2,269)
Total other expense	(975)	(3,938)	(7,636)
Income (loss) before income taxes	61,796	(38,568)	(23,409)
Provision (benefit) for income taxes	2,832	53,885	(1,589)
Net income (loss)	$ 58,964	$ (92,453)	$ (21,820)
OTHER COMPREHENSIVE INCOME (LOSS)			
Foreign currency translation adjustment, net of tax of $645, $1,732 and $0, respectively, for 2017, 2016 and 2015	555	2,711	(4,815)
Comprehensive income (loss)	$ 59,519	$ (89,742)	$ (26,635)
Net income (loss) per share (basic) (Note 11)	$ 1.42	$ (2.94)	$ (0.73)
Net income (loss) per share (diluted) (Note 11)	$ 1.42	$ (2.94)	$ (0.73)
Weighted average number of shares outstanding (Note 11)	41,548	31,500	30,000
Weighted average number of shares outstanding, including dilutive effect (Note 11)	41,639	31,500	30,000
Pro Forma C Corporation Data (unaudited):			
Net loss, as reported		$ (92,453)	$ (21,820)
Taxes on income earned as a non-taxable entity (Note 10)		15,224	391
Taxes due to change to C corporation (Note 10)		53,089	—
Pro forma net loss		$ (24,140)	$ (21,429)
Basic and Diluted (Note 11)		$ (0.56)	$ (0.50)
Weighted average pro forma shares outstanding—basic and diluted (Note 11)		43,107	43,107

(a) Financial information includes the results attributable to Sturgeon for the entire period presented. See Note 14.

(b) Financial information has been recast to include results attributable to Sturgeon. See Note 14.

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

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Common Stock		Common	Members'	Retained Earnings	Additional Paid-In		
	Shares	Amount	Partners	Equity	(Deficit)	Capital	AOCI	Total
	(in thousands)							
Balance at January 1, 2015 (a)	—	$ —	$ 356,322	$ 89,274	$ —	$ —	$ (1,112)	444,484
Net loss	—	—	(27,231)	5,411	—	—	—	(21,820)
Capital distributions	—	—	(1)	(3,901)	—	—	—	(3,902)
Other comprehensive income	—	—	—	—	—	—	(4,815)	(4,815)
Balance at December 31, 2015 (a)	—	—	329,090	90,784	—	—	(5,927)	413,947
Net loss prior to LLC conversion	—	—	(32,085)	—	—	—	—	(32,085)
Net loss of Sturgeon prior to acquisition	—	—	—	(4,045)	—	—	—	(4,045)
Distributions	—	—	—	(5,000)	—	—	—	(5,000)
Equity based compensation	—	—	(19)	—	—	—	—	(19)
LLC Conversion (Note 1)	—	—	(296,986)	—	—	296,986	—	—
Issuance of common stock at public offering, net of offering costs	37,500	375	—	—	—	102,700	—	103,075
Stock-based compensation	—	—	—	—	—	520	—	520
Net loss subsequent to LLC conversion	—	—	—	—	(56,323)	—	—	(56,323)
Other comprehensive income	—	—	—	—	—	—	2,711	2,711
Balance at December 31, 2016 (a)	37,500	375	—	81,739	(56,323)	400,206	(3,216)	422,781
Net income of Sturgeon prior to acquisition	—	—	—	640	—	—	—	640
Stingray acquisition	1,393	14	—	—	—	25,748	—	25,762
Sturgeon acquisition	5,607	56	—	(82,379)	—	78,313	—	(4,010)
Equity based compensation	89	1	—	—	—	3,743	—	3,744
Net income	—	—	—	—	58,324	—	—	58,324
Other comprehensive income	—	—	—	—	—	—	555	555
Balance at December 31, 2017	44,589	$ 446	$ —	$ —	$ 2,001	$ 508,010	$ (2,661)	$ 507,796

(a) Financial information has been recast to include the financial position and results attributable to Sturgeon. See Note 14.

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

MAMMOTH ENERGY SERVICES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2017 (a)	2016 (b)	2015 (b)
Cash flows from operating activities		(in thousands)	
Net income (loss)	$ 58,964	$ (92,453)	$ (21,820)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Equity based compensation	3,741	501	—
Depreciation, depletion, amortization and accretion	92,124	72,315	74,499
Amortization of coil tubing strings	2,855	2,028	2,076
Amortization of debt origination costs	399	603	501
Bad debt expense	16,206	1,968	3,881
Loss (gain) on disposal of property and equipment	69	(702)	1,429
Gain on bargain purchase	(4,012)	—	—
Impairment of long-lived assets	4,146	1,871	12,124
Deferred income taxes	(34,425)	47,899	(5,717)
Changes in assets and liabilities:			
Accounts receivable, net	(231,751)	(4,641)	32,027
Receivables from related parties	(1,096)	(2,462)	9,770
Inventories	(14,238)	(624)	(3,998)
Prepaid expenses and other assets	(7,628)	(198)	4,287
Accounts payable	101,725	1,412	(30,169)
Payables to related parties	1,174	(249)	(756)
Accrued expenses and other liabilities	32,968	2,420	(8,503)
Income taxes payable	36,395	1	8
Net cash provided by operating activities	57,616	29,689	69,639
Cash flows from investing activities:			
Purchases of property and equipment	(132,295)	(11,740)	(28,452)
Purchases of property and equipment from related parties	(1,558)	—	—
Business acquisitions, net	(42,008)	—	—
Proceeds from disposal of property and equipment	907	4,022	1,417
Business combination cash acquired (Note 14)	2,671	—	—
Net cash used in investing activities	(172,283)	(7,718)	(27,035)
Cash flows from financing activities:			
Borrowings on long-term debt	156,850	28,734	14,571
Repayments of long-term debt	(56,950)	(123,734)	(65,612)
Proceeds from initial public offering	—	105,839	—
Initial public offering costs	—	(2,764)	—
Debt issuance costs	—	—	(614)
Repayment of acquisition-related long-term debt	(8,851)	—	—
Capital distributions	—	(5,000)	(3,902)
Net cash provided by (used in) financing activities	91,049	3,075	(55,557)
Effect of foreign exchange rate on cash	16	154	(227)
Net (decrease) increase in cash and cash equivalents	(23,602)	25,200	(13,180)
Cash and cash equivalents at beginning of period	29,239	4,039	17,219
Cash and cash equivalents at end of period	$ 5,637	$ 29,239	$ 4,039

MAMMOTH ENERGY SERVICES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2017 (a)	2016 (b)	2015 (b)
Supplemental disclosure of cash flow information:		(in thousands)	
Cash paid for interest	$ 3,656	$ 3,707	$ 5,192
Cash paid for income taxes	$ 840	$ 3,588	$ 3,888
Supplemental disclosure of non-cash transactions:			
Acquisition of Stingray Cementing LLC and Stingray Energy Services LLC	$ 23,091	$ —	$ —
Purchases of property and equipment included in accounts payable	$ 15,038	$ 2,789	$ 741

(a) Financial information includes the results attributable to Sturgeon for the entire period presented. See Note 14.

(b) Financial information has been recast to include results attributable to Sturgeon. See Note 14.

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

1. Organization and Basis of Presentation

The accompanying consolidated financial statements were prepared in accordance with the rules and regulations of the Securities and Exchange Commission, and reflect all adjustments, which in the opinion of management are necessary for the fair presentation of the results.

Mammoth Energy Services, Inc. ("Mammoth Inc." or the "Company"), together with its subsidiaries, is an integrated, growth-oriented energy services company serving companies engaged in the exploration and development of North American onshore unconventional oil and natural gas reserves as well as government-funded utilities, private utilities, public investor owned utilities and co-operative utilities engaged in energy infrastructure. The Company was incorporated in Delaware in June 2016 as a wholly-owned subsidiary of Mammoth Energy Partners, LP, a Delaware limited liability company (the "Partnership" or the "Predecessor"). The Partnership was originally formed by Wexford Capital LP (“Wexford”) in February 2014 as a holding company under the name Redback Energy Services Inc. and was converted to a Delaware limited partnership in August 2014. On November 24, 2014, Mammoth Energy Holdings, LLC (“Mammoth Holdings,” an entity controlled by Wexford), Gulfport Energy Corporation (“Gulfport”) and Rhino Resource Partners LP (“Rhino”) (collectively known as “Predecessor Interest”) contributed their interest in certain of the entities presented below to the Partnership in exchange for 20 million limited partner units. Mammoth Energy Partners GP, LLC (the “General Partner”) held a non-economic general partner interest in the Partnership.

The following companies (“Operating Entities”) are included in these consolidated financial statements: Bison Drilling and Field Services, LLC (“Bison Drilling”), formed November 15, 2010; Bison Trucking LLC (“Bison Trucking”), formed August 9, 2013; White Wing Tubular Services LLC (“White Wing”), formed July 29, 2014; Barracuda Logistics LLC (“Barracuda”), formed October 24, 2014; Mr. Inspections LLC (“MRI”), formed January 25, 2015; Panther Drilling Systems LLC (“Panther”), formed December 11, 2012; Redback Energy Services, LLC (“Redback Energy”), formed October 6, 2011; Redback Coil Tubing, LLC (“Coil Tubing”), formed May 15, 2012; Redback Pump Down Services LLC (“Pump Down”), formed January 16, 2015; Muskie Proppant LLC (“Muskie”), formed September 14, 2011; Stingray Pressure Pumping LLC (“Pressure Pumping”), acquired November 24, 2014; Stingray Logistics LLC (“Logistics”), acquired November 24, 2014; Great White Sand Tiger Lodging Ltd. (“Sand Tiger”), formed October 1, 2007, Silverback Energy Services LLC ("Silverback"), formed June 8, 2016; Mammoth Equipment Leasing LLC, formed on November 14, 2016; Cobra Acquisitions LLC ("Cobra"), formed January 9, 2017; Cobra Energy LLC (“Cobra Energy”), formed January 25, 2017; Piranha Proppant LLC ("Piranha"), formed March 28, 2017; Higher Power Electrical LLC ("Higher Power"), acquired April 21, 2017; Stingray Energy Services LLC ("SR Energy"), acquired June 5, 2017; Stingray Cementing LLC ("Cementing"), acquired June 5, 2017; Sturgeon Acquisitions LLC (“Sturgeon”), acquired June 5, 2017; Taylor Frac, LLC (“Taylor Frac”), acquired June 5, 2017; Taylor Real Estate Investments, LLC (“Taylor RE”), acquired June 5, 2017; South River Road, LLC (“South River”), acquired June 5, 2017; 5 Star Electric, LLC (“5 Star”), acquired July 1, 2017; and Tiger Shark Logistics LLC (“Tiger Shark”), formed October 20, 2017.

On October 12, 2016, the Partnership was converted into a Delaware limited liability company named Mammoth Energy Partners LLC (“Mammoth LLC”), and then Mammoth Holdings, Gulfport and Rhino, as all the members of Mammoth LLC, contributed their member interests in Mammoth LLC to Mammoth Inc. Prior to the conversion and the contribution, Mammoth Inc. was a wholly-owned subsidiary of the Partnership. Following the conversion and the contribution, Mammoth LLC (as the converted successor to the Partnership) was a wholly-owned subsidiary of Mammoth Inc. Mammoth Inc. did not conduct any material business operations until Mammoth LLC was contributed to it. On October 19, 2016, Mammoth Inc. closed its initial public offering of 7,750,000 shares of common stock (the "IPO"), which included an aggregate of 250,000 shares that were offered by Mammoth Holdings, Gulfport and Rhino, at a price to the public of $15.00 per share.

Net proceeds to Mammoth Inc. from its sale of 7,500,000 shares of common stock were approximately $103.1 million. On the closing date of the IPO, Mammoth Inc. repaid all outstanding borrowings under its revolving credit facility and used the remaining net proceeds for general corporate purposes, including the acquisition of additional equipment and complementary businesses that enhanced its existing service offerings, broadened its service offerings and expanded its customer relationships.

On March 27, 2017, the Company entered into a definitive asset purchase agreement, as amended as of May 24, 2017 (the “Purchase Agreement”), with Chieftain Sand and Proppant, LLC and Chieftain Sand and Proppant Barron, LLC, unrelated third party sellers (the “Chieftain Sellers”), following Mammoth’s successful bid in a bankruptcy court auction for substantially all of the assets of the Sellers (the “Chieftain Acquisition”). The Chieftain Acquisition closed on May 26, 2017 for the purchase price of $36.3 million, including closing adjustments. Mammoth funded the purchase price for the Chieftain Acquisition with cash on hand and borrowings under its revolving credit facility. Refer to Note 14 - Acquisitions for additional disclosure regarding the Chieftain Acquisition.

On June 5, 2017, the Company completed the acquisition of (1) Sturgeon, a Delaware limited liability company, which included the acquisition of Sturgeon's wholly-owned subsidiaries Taylor Frac, a Wisconsin limited liability company, Taylor RE, a Wisconsin limited liability company, and South River, a Wisconsin limited liability company, (2) SR Energy, a Delaware limited liability company; and (3) Cementing, a Delaware limited liability company (together with SR Energy, the “Stingray Acquisition”) in exchange for the issuance by Mammoth of an aggregate of 7,000,000 shares of its common stock.

Prior to its acquisition of Sturgeon, the Company and Sturgeon were under common control and it is required under accounting principles generally accepted in the Unites States of America ("GAAP") to account for this common control acquisition in a manner similar to the pooling of interest method of accounting. Therefore, the Company's historical financial information for all periods included in the accompanying financial statements has been recast to combine Sturgeon with the Company as if the acquisition had been effective since the date Sturgeon commenced operations. Refer to Note 14 - Acquisitions for additional disclosure regarding the acquisition of Sturgeon.

At December 31, 2017 and December 31, 2016, Mammoth Holdings, Gulfport and Rhino owned the following share of outstanding common stock of Mammoth Inc:

	At December 31, 2017		December 31, 2016	
	Share Count	% Ownership	Share Count	% Ownership
Mammoth Holdings	25,009,319	56.1%	20,443,903	54.5%
Gulfport	11,171,887	25.1%	9,073,750	24.2%
Rhino	568,794	1.3%	232,347	0.6%
Outstanding shares owned by related parties	36,750,000	82.5%	29,750,000	79.3%
Total outstanding	44,589,306	100.0%	37,500,000	100.0%

Operations

The Company's pressure pumping services include equipment and personnel used in connection with the completion and early production of oil and natural gas wells. The Company's infrastructure services include electric utility contracting services focused on the repair, upgrade, maintenance and construction of transmission and distribution networks. The Company’s infrastructure services also provide storm repair and restoration services in response to hurricane, ice or other storm-related damage. The Company's natural sand proppant services include the distribution and production of natural sand proppant that is used primarily for hydraulic fracturing in the oil and gas industry. The Company's contract land and directional drilling services provides drilling rigs and directional tools for both vertical and horizontal drilling of oil and natural gas wells. The Company also provides other energy services, including coil tubing units used to enhance the flow of oil and natural gas, flowback, cementing, equipment rentals and remote accommodations.

All of the Company’s operations are in North America. The Company operates its oil and natural gas businesses in the Permian Basin, the Utica Shale, the Eagle Ford Shale, the Marcellus Shale, the Granite Wash, the SCOOP, the STACK, the Cana-Woodford Shale, the Cleveland Sand and the oil sands located in Northern Alberta, Canada. The Company operates its energy infrastructure services in the northeast, southwest and midwest portions of the United States and Puerto Rico. The Company's oil and natural gas business depends in large part on the conditions in the oil and natural gas industry and, specifically, on the amount of capital spending by its customers. Any prolonged increase or decrease in oil and natural gas prices affects the levels of exploration, development and production activity, as well as the entire health of the oil and natural gas industry. Changes in the commodity prices for oil and natural gas could have a material effect on the Company’s results of operations and financial condition. The Company’s business also depends on infrastructure spending on maintenance, upgrade, expansion and repair and restoration. Any prolonged decrease in spending by electric utility companies or delays or reductions in government appropriations could have a material adverse effect on the Company’s results of operations and financial condition.

2. Summary of Significant Accounting Policies

(a) Principles of Consolidation

The consolidated financial statements are prepared in accordance with GAAP. All material intercompany accounts and transactions between the entities within the Company have been eliminated. Certain prior period amounts have been reclassified to conform to the current period presentation.

(b) Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the 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 those estimates. Significant estimates include but are not limited to the Company's sand reserves and their impact on calculating depletion expense, allowance for doubtful accounts, asset retirement obligations, reserves for self-insurance, depreciation and amortization of property and equipment, business combination valuations, amortization of intangible assets, and future cash flows and fair values used to assess recoverability and impairment of long-lived assets, including goodwill.

(c) Cash and Cash Equivalents

All highly liquid investments with an original maturity of three months or less are considered cash equivalents. The Company maintains its cash accounts in financial institutions that are insured by the Federal Deposit Insurance Corporation, with the exception of cash held by Sand Tiger in a Canadian financial institution. At December 31, 2017, we had $2.5 million, in Canadian dollars, of cash in Canadian accounts. Cash balances from time to time may exceed the insured amounts; however, the Company has not experienced any losses in such accounts and does not believe it is exposed to any significant credit risks on such accounts.

(d) Accounts Receivable

Accounts receivable include amounts due from customers for services performed and are recorded as the work progresses. The Company grants credit to customers in the ordinary course of business and generally does not require collateral. Most areas in which the Company operates provide for a mineral lien or mechanic’s lien against the property on which the service is performed if the lien is filed within the statutorily specified time frame. Customer balances are generally considered delinquent if unpaid by the 30th day following the invoice date and credit privileges may be revoked if balances remain unpaid.

The Company regularly reviews receivables and provides for estimated losses through an allowance for doubtful accounts. In evaluating the level of established reserves, the Company makes judgments regarding its customers’ ability to make required payments, economic events, and other factors. As the financial conditions of customers change, circumstances develop, or additional information becomes available, adjustments to the allowance for doubtful accounts may be required. In the event the Company was to determine that a customer may not be able to make required payments, the Company would increase the allowance through a charge to income in the period in which that determination is made. Uncollectible accounts receivable are periodically charged against the allowance for doubtful accounts once final determination is made of their uncollectability.

Following is a roll forward of the allowance for doubtful accounts for the years ended December 31, 2017, 2016 and 2015 (in thousands):

Balance, January 1, 2015	$	590
Additions charged to expense		3,881
Deductions for uncollectible receivables written off		(459)
Balance, December 31, 2015		4,012
Additions charged to expense		1,968
Deductions for uncollectible receivables written off		(603)
Balance, December 31, 2016		5,377
Additions charged to expense		16,206
Additions - other		179
Deductions for uncollectible receivables written off		(25)
Balance, December 31, 2017	$	21,737

In October 2017, Cobra, one of the Company's subsidiaries, entered into a contract with the Puerto Rico Electric Power Authority ("PREPA") to perform repairs to PREPA's electrical grid as a result of Hurricane Maria. At December 31, 2017, the Company reviewed receivables due from PREPA and made specific reserves consistent with Company policy which resulted in additions to allowance for doubtful accounts totaling $16.0 million.

Additionally, as discussed in Note 1, prolonged declines in oil and natural gas commodity pricing can impact the overall health of the oil and natural gas industry. The year ended December 31, 2017 contained such pricing conditions which may lead to enhanced risk of uncollectiblity on certain receivables. As such, the Company has made specific reserves consistent with Company policy which resulted in additions to allowance for doubtful accounts totaling $0.2 million. The Company will continue to pursue collection until such time as final determination is made consistent with Company policy.

(e) Inventory

Inventory consists of raw sand and processed sand available for sale, chemicals and other products sold as a bi-product of completion and production operations, and supplies used in performing services. Inventory is stated at the lower of cost or market (net realizable value) on an average cost basis. The Company assesses the valuation of its inventories based upon specific usage and future utility.

Inventory manufactured at the Company's sand production facilities includes direct excavation costs, processing costs and overhead allocation. Stockpile tonnages are calculated by measuring the number of tons added and removed from the stockpile. Costs are calculated on a per ton basis and are applied to the stockpiles based on the number of tons in the stockpile. Inventory transported for sale at the Company's terminal facility includes the cost of purchased or manufactured sand, plus transportation related charges.

Coil tubing strings of various widths, diameters and lengths are included in inventory. The strings are used in providing specialized services to customers who are primarily operators of oil or gas wells and are used at various rates based on factors such as well conditions (i.e. pressure and friction), vertical and horizontal length of the well, running speed of the string in the well, and total running feet accumulated to the string. The Company obtains usage information from data acquisition software and other established assessment methods and attempts to amortize the strings over their estimated useful life. In no event will a string be amortized over a period longer than 12 months. Amortization of coil strings is included in services cost of revenue in the Consolidated Statements of Comprehensive Income (Loss) and totaled $2.9 million, $2.0 million and $2.1 million for the years ended December 31, 2017, 2016 and 2015, respectively.

(f) Prepaid Expenses

Prepaid expenses primarily consist of insurance costs. Insurance costs are expensed over the periods that these costs benefit.

(g) Property and Equipment

Property and equipment, including renewals and betterments, are capitalized and stated at cost, while maintenance and repairs that do not increase the capacity, improve the efficiency or safety, or improve or extend the useful life are charged to operations as incurred. Disposals are removed at cost, less accumulated depreciation, and any resulting gain or loss is recorded in operations. Depreciation is calculated using the straight-line method over the shorter of the estimated useful life, or the remaining lease term, as applicable. Depreciation does not begin until property and equipment is placed in service. Once placed in service, depreciation on property and equipment continues while being repaired, refurbished, or between periods of deployment.

(h) Sand reserves

Sand reserve costs include engineering, mineralogical studies and other related costs to develop the mine, the removal of overburden to initially expose the mineral and building access ways. Exploration costs are expensed as incurred and classified as product cost of revenue. Capitalization of mine development project costs begins once the deposit is classified as proven and probable reserves. Drilling and related costs are capitalized for deposits where proven and probable reserves exist and the activities are directed at obtaining additional information on the deposit or converting non-reserve minerals to proven and probable reserves and the benefit is to be realized over a period greater than one year. Mining property and development costs are amortized using the units-of-production method on estimated measured tons in in-place reserves. The impact of revisions to reserve estimates is recognized on a prospective basis.

(i) Long-Lived Assets

The Company reviews long-lived assets for recoverability in accordance with the provisions of Financial Accounting Standards Board ("FASB") Accounting Standard Codification (“ASC”) Topic 360, *Impairment or Disposal of Long-Lived Assets*, which requires that long-lived assets be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. Recoverability of assets is measured by comparing the carrying amount of an asset to future undiscounted net cash flows expected to be generated by the asset. These evaluations for impairment are significantly impacted by estimates of revenues, costs and expenses, and other factors. If long-lived assets are considered to be impaired, the impairment to be recognized is measured by the amount in which the carrying amount of the assets exceeds the fair value of the assets. For the years ended December 31, 2017, 2016 and 2015, the Company recognized impairment losses of $4.1 million, $1.9 million and $9.9 million, respectively, on various fixed assets included in property, plant and equipment, net in the Consolidated Balance Sheets. Additionally, during the year ended December 31, 2015, the Company recognized impairment losses of $1.9 million, $0.3 million and $0.1 million, respectively, on a terminated long term contractual agreement, intangible assets and goodwill.

(j) Goodwill

Goodwill is tested for impairment annually, or more frequently if events or changes in circumstances indicate that goodwill might be impaired. The impairment test is a two-step process. First, the fair value of each reporting unit is compared to its carrying value to determine whether an indication of impairment exists. If impairment is indicated, then the implied value of the reporting unit’s goodwill is determined by allocating the unit’s fair value to its assets and liabilities as if the reporting unit had been acquired in a business combination. The fair value of the reporting unit is determined using the discounted cash flow approach, excluding interest. The impairment for goodwill is measured as the excess of its carrying value over its implied value. Goodwill was tested for impairment as of December 31, 2017. For the years ended December 31, 2017 and 2016, no impairment losses were recognized. During year ended December 31, 2015, the Company recognized impairments of $0.1 million.

(k) Other Non-Current Assets

Other non-current assets primarily consist of deferred financing costs on our credit facility (see Note 8) and sales tax receivables.

(***l) Asset Retirement Obligations***

Mine reclamation costs, future remediation costs for inactive mines and other contractual site remediation costs are accrued based on management’s best estimate at the end of each period of the costs expected to be incurred at a site. Such cost estimates include, where applicable, ongoing care, maintenance and monitoring costs. Changes in estimates at inactive mines are reflected in earnings in the period an estimate is revised.

Following is a roll forward of the Company's asset retirement obligations for the years ended December 31, 2017 and 2016 (in thousands):

	December 31,	
	2017	2016
Balance as of beginning of period	$ 260	$ 95
Liabilities assumed through acquisition	1,732	—
Accretion expense	124	162
Foreign currency translation adjustment	7	3
Asset retirement obligation as of end of period	$ 2,123	$ 260

(m) Business Combinations
The Company accounts for its business acquisitions under the acquisition method of accounting as indicated in FASB ASC No. 805, *Business Combinations*, which requires the acquiring entity in a business combination to recognize the fair value of all assets acquired, liabilities assumed and any noncontrolling interest in the acquiree and establishes the acquisition date as the fair value measurement point. Accordingly, the Company recognizes assets acquired and liabilities assumed in business combinations, including contingent assets and liabilities and noncontrolling interest in the acquiree, based on fair value estimates as of the date of acquisition. In accordance with FASB ASC No. 805, the Company recognizes and measures goodwill, if any, as of the acquisition date, as the excess of the fair value of the consideration paid over the fair value of the identified net assets acquired.

When the Company acquires a business from an entity under common control, whereby the companies are ultimately controlled by the same party or parties both before and after the transaction, it is treated for accounting purposes in a manner similar to the pooling of interest method of accounting. The assets and liabilities are recorded at the transferring entity’s historical cost instead of reflecting the fair market value of assets and liabilities.

(n) Amortizable Intangible Assets
Intangible assets subject to amortization include customer relationships and trade names. Customer relationships are amortized based on an estimated attrition factor and trade names are amortized over their estimated useful lives. There were no impairment losses recognized for amortizable assets for the years ended December 31, 2017 or 2016. During the year ended December 31, 2015, the Company terminated one customer relationship and impaired the remaining unamortized value of the intangible and recognized an impairment loss of $0.3 million.

(o) Fair Value of Financial Instruments
The Company's financial instruments consist of cash and cash equivalents, trade receivables, trade payables, amounts receivable or payable to related parties, and long-term debt. The carrying amount of cash and cash equivalents, trade receivables, receivables from related parties and trade payables approximates fair value because of the short-term nature of the instruments. The fair value of long-term debt approximates its carrying value because the cost of borrowing fluctuates based upon market conditions.

(p) Revenue Recognition
The Company generates revenue from multiple sources within its operating segments. In all cases, revenue is recognized when services are performed, collection of the receivable is probable, persuasive evidence of an arrangement exists, and the price is fixed and determinable. The majority of our services are sold without warranty or right of return. Under certain customer contracts in our infrastructure services segment, the Company warrants equipment and labor performed for a specified period following substantial completion of the work. Taxes assessed on revenue transactions are presented on a net basis and are not included in revenue.

Pressure pumping services are typically provided based upon a purchase order, contract, or on a spot market basis. Services are provided on a day rate, contracted, or hourly basis, and revenue is recognized as the work progresses. Jobs for these services are typically short-term in nature and range from a few hours to multiple days. Revenue is recognized upon the completion of each day’s work based upon a completed field ticket, which includes the charges for the services performed, mobilization of the equipment to the location, and personnel. Additional revenue is generated through labor charges and the sale of consumable supplies that are incidental to the service being performed. The labor charges and the use of consumable supplies are reflected on the completed field tickets.

Infrastructure services revenues are recognized as the work progresses based on the days completed or as the contract is completed. These services may be provided pursuant to master service agreements, repair and maintenance contracts or fixed price and non-fixed price installation contracts. Pricing under these contracts may be unit priced, cost-plus/hourly (or time and materials basis) or fixed price (or lump sum basis), and the final terms and prices of these contracts are frequently negotiated with the customer. Under unit-based contracts, the utilization of an output-based measurement is appropriate for revenue recognition. Under cost-plus/hourly and time and materials type contracts, the Company recognizes revenue on an input basis, as labor hours are incurred and services are performed.

Natural sand proppant revenues are recognized when legal title passes to the customer, which may occur at the production facility, rail origin or at the destination terminal. At that point, delivery has occurred, evidence of a contractual arrangement exists, the price is fixed and determinable, and collectability is reasonably assured. Transportation services revenues are recognized as the services have been completed, meaning the related services have been rendered. At that point, delivery of service has occurred, evidence of a contractual arrangement exists and collectability is reasonably assured. Amounts received from customers in advance of sand deliveries are recorded as deferred revenue. Customers have the ability to make up contractual short falls by achieving higher-than-contracted volumes over the shortfall window. Contractual shortfall revenue is deemed not probable until the end of the measurement period.

Contract drilling services are provided under daywork or footage contracts, and revenue is recognized as the work progresses based on the days completed or the feet drilled, as applicable. Mobilization revenue and costs for daywork and footage contracts are recognized over the days of actual drilling.

Directional drilling services are provided on a day rate or hourly basis, and revenue is recognized as work progresses. Proceeds from customers for the cost of equipment that is damaged or lost down-hole are reflected as service revenues as this is deemed to be perfunctory or inconsequential to the underlying service being performed.

Our other operations consist of well services, including coil tubing, pressure control, flowback, cementing, equipment rentals and remote accommodations. Well services are typically provided based upon a purchase order, contract, or on a spot market basis. Services are provided on a day rate, contracted, or hourly basis, and revenue is recognized as the work progresses. Jobs for these services are typically short-term in nature and range from a few hours to multiple days. Our equipment rental services are recognized upon completion of each day's work based on a completed field ticket. Revenue from remote accommodation services is recognized when rooms are occupied and services have been rendered. Advance deposits on rooms and special events are deferred until services are provided to the customer. During the year ended December 31, 2016, the Company recognized and collected $0.5 million in business interruption insurance proceeds which is included in Service revenue in the accompanying Consolidated Statements of Comprehensive Income (Loss). The proceeds resulted from loss of revenue relating to wildfires that forced evacuation of personnel.

The timing of revenue recognition may differ from contract billing or payment schedules, resulting in revenues that have been earned but not billed (“unbilled revenue”) or amounts that have been billed, but not earned (“deferred revenue”). The Company had $65.9 million and $2.7 million, respectively, of unbilled revenue included in accounts receivable, net in the Consolidated Balance Sheets at December 31, 2017 and 2016. The Company had $9.1 million and $10.5 million, respectively, of unbilled revenue included in receivables from related parties in the Consolidated Balance Sheets at December 31, 2017 and 2016. The Company had $15.2 million of deferred revenue included in accrued expenses and other current liabilities in the Consolidated Balance Sheets at December 31, 2017. The Company did not have any deferred revenue at December 31, 2016.

(q) Earnings (Loss) per Share

Earnings (loss) per share is computed by dividing net income (loss) by the weighted average number of outstanding shares. See Note 11.

(r) Unaudited Pro Forma Earnings (Loss) per Share

The Company’s pro forma basic earnings (loss) per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period, as if the common shares issued at the IPO were outstanding for the full year of 2016 and 2015. Diluted earnings per share reflects the potential dilution, using the treasury stock method. During periods in which the Company realizes a net loss, restricted stock awards would be anti-dilutive to net loss per share and conversion into common stock is assumed not to occur.

(s) Equity-based Compensation

The Company records equity-based payments at fair value on the date of grant, and expenses the value of these equity-based payments in compensation expense over the applicable vesting periods. See Note 12.

(t) Stock-based Compensation

The Company's stock-based compensation program consists of restricted stock units granted to employees and restricted stock units granted to non-employee directors under the Mammoth Energy Services, Inc. 2016 Incentive Plan (the "2016 Plan"). The Company recognizes in its financial statements the cost of employee services received in exchange for restricted stock based on the fair value of the equity instruments as of the grant date. In general, this value is amortized over the vesting period; for grants with a non-substantive service condition, this value is recognized immediately. Amounts are recognized in cost of revenues and selling, general, and administrative expenses. See Note 13.

(u) Income Taxes

On October 12, 2016, immediately prior to the IPO of Mammoth Inc., the Partnership converted into a limited liability company named Mammoth Energy Partners LLC ("Mammoth LLC"). All equity interests in Mammoth LLC were contributed to Mammoth Inc. and Mammoth LLC became a wholly owned subsidiary of Mammoth Inc. Mammoth Inc. is a C corporation under the Internal Revenue Code and is subject to income tax. Historically, Mammoth LLC and each of the Operating Entities other than Sand Tiger was treated as a partnership for federal income tax purposes. As a result, essentially all taxable earnings and losses were passed through to its members, and Mammoth LLC did not pay any federal income taxes at the entity level. Mammoth Inc. owns the member interests in several single member limited liability companies. These LLCs are subject to taxation in Texas where the Company does business; therefore, the Company may provide for income taxes attributable to that state on a current basis. The income tax provision for the period before the IPO has been prepared on a separate return basis for Mammoth LLC and all of its subsidiaries that were treated as a partnership for federal income tax purposes.

Subsequent to the IPO, the Company's operations are included in a consolidated federal income tax return and other state returns. Accordingly, the Company has recognized deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases for all our subsidiaries as if each entity were a corporation, regardless of its actual characterization for U.S. federal income tax purposes.

The Company's effective tax rate was 4.9% for the year ended December 31, 2017. The Company's effective tax rate was 34.6%, excluding the conversion to a C Corporation (See Note 1), for the year ended December 31, 2016. The Company's effective tax rate can fluctuate as a result of, among other things, the impact of changes to corporate income tax laws, state income taxes, permanent differences and changes in pre-tax income.

Under FASB ASC 740, deferred tax assets and liabilities are recognized 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 statutory tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of deferred tax assets and liabilities as a result of a change in tax rate is recognized in the period that includes the statutory enactment date. A valuation allowance for deferred tax assets is recognized when it is more likely than not that the benefit of deferred tax assets will not be realized. To assess that likelihood, the Company uses estimates and judgments regarding future taxable income, as well as the jurisdiction in which such taxable income is generated, to determine whether a valuation allowance is required. During the year ended December 31, 2017, the Company recorded a valuation allowance of $15.5 million related to foreign tax credits that are not expected to be utilized.

On December 22, 2017, the United States enacted the Tax Cuts and Jobs Act (the "Tax Act"). The Tax Act significantly changed US corporate income tax laws by, among other things, reducing the US corporate income tax rate from 35% to 21% starting in 2018 and creating a territorial tax system with a one-time mandatory tax on previously deferred foreign earnings of US subsidiaries. As a result, the Company recorded a one-time reduction to income tax expense of $31.0 million during the fourth quarter of 2017, which is included in Provision (benefit) for income taxes in the Consolidated Statements of Comprehensive Income (Loss). See Note 10 for further information.

The Company has included a pro forma provision for income taxes assuming it had been taxed as a C corporation in all periods prior to the conversion and contribution as part of its earnings per share calculation in Note 11. The unaudited pro forma data are presented for informational purposes only, and do not purport to project our results of operations for any future period or its financial position as of any future date.

Certain income from our infrastructure services segment and income from our remote accommodations business is subject to foreign income taxes, and such taxes are provided in the financial statements pursuant to FASB ASC 740, *Income Taxes.*

The Company evaluates tax positions taken or expected to be taken in preparation of its tax returns and disallows the recognition of tax positions that do not meet a “more likely than not” threshold of being sustained upon examination by the taxing authorities. During the years ended December 31, 2017 and 2016, no material uncertain tax positions existed. Penalties and interest, if any, are recognized in general and administrative expense. The Company's 2017, 2016, 2015 and 2014 income tax returns remain open to examination by the applicable taxing authorities.

(v) Foreign Currency Translation

For foreign operations, assets and liabilities are translated at the period-end exchange rate, and income statement items are translated at the average exchange rate for the period. Resulting translation adjustments are recorded within accumulated other comprehensive income (loss). Assets and liabilities denominated in foreign currencies, if any, are re-measured at the balance sheet date. Transaction gains or losses are included as a component of current period earnings.

(w) Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. Management has established procedures for the ongoing evaluation of the Company’s operations, to identify potential environmental exposures and to comply with regulatory policies and procedures. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future revenue generation are expensed as incurred. Liabilities are recorded when environmental costs are probable, and the costs can be reasonably estimated. The Company maintains insurance which may cover in whole or in part certain environmental expenditures. As of December 31, 2017 and 2016, there were no probable environmental matters.

(x) Other Comprehensive Income (Loss)

Comprehensive income (loss) consists of net income (loss) and other comprehensive income (loss). Other comprehensive income (loss) included certain changes in equity that are excluded from net income (loss). Specifically, cumulative foreign currency translation adjustments are included in accumulated other comprehensive income (loss).

(y) Concentrations of Credit Risk and Significant Customers

Financial instruments that potentially subject the Company to concentrations of credit risk consist of cash and cash equivalents in excess of federally insured limits and trade receivables. Following is a summary of our significant customers based on accounts receivable balances at December 31, 2017 and 2016 and revenues derived for the years ended December 31, 2017, 2016 and 2015:

	REVENUES			ACCOUNTS RECEIVABLE	
	Years Ended December 31,			At December 31,	
	2017	2016	2015	2017	2016
Customer A[(a)]	30%	57%	46%	12%	57%
Customer B[(b)]	29%	—	—	56%	—
Customer C[(c)]	1%	11%	6%	—	9%
Customer D[(d)]	—	—	12%	—	—

a. Customer A is a related party customer. Revenues and the related accounts receivable balances earned from Customer A were derived from the Company's pressure pumping services segment, natural sand proppant services segment, contract land and directional drilling services segment and other businesses.

b. Customer B is a third-party customer. Revenues and the related accounts receivable balances earned from Customer B were derived from the Company's infrastructure services segment.

c. Customer C is a third-party customer. Revenues and the related accounts receivable balances earned from Customer C were derived from the Company's remote accommodations business.

d. Customer D is a third-party customer. Revenues earned from Customer D were derived from the Company's pressure pumping services segment. No revenues were earned from Customer D during the years ended December 31, 2017 or 2016.

(z) New Accounting Pronouncements

In July 2015, the FASB issued ASU No. 2015-11, "*Inventory (Topic 330): Simplifying the Measurement of Inventory*," which changes inventory measured using any method other than last-in, first-out (LIFO) or the retail inventory method (for example, inventory measured using first-in, first-out (FIFO) or average cost) at the lower of cost and net realizable value. ASU 2015-11 is effective for annual and interim reporting periods beginning after December 15, 2016, with early adoption permitted. On January 1, 2017, the Company adopted this ASU and it did not impact our consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, "*Revenue from Contracts with Customers,*" which supersedes the revenue recognition requirements in Topic 605, *Revenue Recognition*, and most industry-specific guidance. Subsequent to ASU 2014-09, the FASB issued several related ASU's to clarify the application of the revenue recognition standard. The core principle of the new standard is for the recognition of revenue to depict the transfer of goods or services to customers in amounts that reflect the payment to which the company expects to be entitled in exchange for those goods or services. The new standard will also result in enhanced revenue disclosures, provide guidance for transactions that were not previously addressed comprehensively and improve guidance for multiple-element arrangements. The ASU is effective for annual periods beginning after December 15, 2016, and interim periods within those years. The new standard permits retrospective application using either of the following methodologies: (i) restatement of each prior reporting period presented (full retrospective method) or (ii) recognition of a cumulative-effect adjustment as of the date of initial application (modified retrospective method). In July 2015, the FASB decided to defer the effective date by one year (until 2018). The Company has evaluated the impact of this ASU on its consolidated financial statements. This evaluation required, among other things, a review of existing contracts the Company has with its customers within each of the revenue streams identified within its business, including pressure pumping services, infrastructure services, natural sand proppant services, contract land and directional drilling services and other services. The Company did not identify any changes to its revenue recognition policies that would result in a material effect on the timing of the Company's revenue recognition or its financial position, results of operations, net income or cash flows. Additionally, the Company does not believe further disaggregation of revenue will be required under the new standard. The adoption of this ASU will have an impact on the Company's revenue related disclosures and internal controls over financial reporting as the Company's revenue recognition related disclosures will expand upon adoption of the new standard. The Company is currently in the process of finalizing documentation of new policies, procedures, systems, controls and data requirements as the standard is implemented. The Company will be in a position to begin reporting under the new standard beginning in the first quarter of 2018, using the modified retrospective method.

In February 2016, the FASB issued ASU No, 2016-2 "Leases" amending the current accounting for leases. Under the new provisions, all lessees will report a right-of-use asset and a liability for the obligation to make payments for all leases with the exception of those leases with a term of 12 months or less. All other leases will fall into one of two categories: (i) a financing lease or (ii) an operating lease. Lessor accounting remains substantially unchanged with the exception that no leases entered into after the effective date will be classified as leveraged leases. For sale leaseback transactions, a sale will only be recognized if the criteria in the new revenue recognition standard are met. ASU 2016-2 is effective for fiscal years beginning after December 15, 2018, and interim periods within that fiscal year. Early adoption is permitted. This new leasing guidance will impact the Company in situations where it is the lessee, and in certain circumstances it will have a right-of-use asset and lease liability on its consolidated financial statements. The Company is currently evaluating the effect the new guidance will have on our consolidated financial statements and results of operations.

3. Inventories

A summary of the Company's inventories is shown below (in thousands):

	December 31,	
	2017	**2016**
Supplies	$ 9,437	$ 4,021
Raw materials	219	76
Work in process	2,370	205
Finished goods	5,788	1,822
Total inventory	$ 17,814	$ 6,124

4. Property, Plant and Equipment

Property, plant and equipment include the following (in thousands):

	Useful Life	December 31, 2017	December 31, 2016
Pressure pumping equipment	3-5 years	$ 190,211	$ 96,501
Drilling rigs and related equipment	3-15 years	132,260	138,527
Machinery and equipment[(a)]	7-20 years	97,569	35,548
Buildings	15-39 years	45,992	54,833
Vehicles, trucks and trailers[(b)]	5-10 years	54,055	33,141
Coil tubing equipment	4-10 years	28,053	28,019
Land	N/A	11,317	5,040
Land improvements	15 years or life of lease	9,614	3,641
Rail improvements	10-20 years	5,540	4,277
Other property and equipment	3-12 years	12,687	11,462
		587,298	410,989
Deposits on equipment and equipment in process of assembly		20,348	9,427
		607,646	420,416
Less: accumulated depreciation, depletion, amortization and accretion[(c)]		256,629	178,296
Property, plant and equipment, net		$ 351,017	$ 242,120

a. Included in machinery and equipment are assets under capital leases totaling $1.8 million for the year ended December 31, 2017.
b. Included in vehicles, trucks and trailers are assets under capital leases totaling $1.0 million and $1.1 million, respectively, for the years ended December 31, 2017 and 2016.
c. Accumulated depreciation for assets under capital leases totaled $0.8 million and $0.9 million, respectively, for the years ended December 31, 2017 and 2016.

Proceeds from customers for horizontal and directional drilling services equipment, damaged or lost down-hole are reflected in revenue with the carrying value of the related equipment charged to cost of service revenues and are reported as cash inflows from investing activities in the statement of cash flows. For the years ended December 31, 2017, 2016 and 2015, proceeds from the sale of equipment damaged or lost down-hole were $0.5 million, $0.7 million and $0.4 million, respectively, and gain on sales of equipment damaged or lost down-hole were $0.3 million, $0.4 million and $0.1 million, respectively.

A summary of depreciation, depletion, amortization and accretion expense is shown below (in thousands):

	Years Ended December 31, 2017	2016	2015
Depreciation expense[(a)]	$ 81,191	$ 62,196	$ 64,568
Accretion and depletion expense (see Note 2)	1,632	1,048	829
Amortization expense (see Note 6)	9,301	9,071	9,102
Depreciation, depletion, amortization and accretion	$ 92,124	$ 72,315	$ 74,499

a. Includes depreciation expense for assets under capital leases totaling $0.4 million, $0.5 million and $0.6 million, respectively, for the years ended December 31, 2017, 2016 and 2015.

Deposits on equipment and equipment in process of assembly represents deposits placed with vendors for equipment that is in the process of assembly and purchased equipment that is being outfitted for its intended use. The equipment is not yet placed in service.

5. Impairments

A summary of our impairments is as follows (in thousands):

	December 31,		
	2017	2016	2015
Flowback equipment [a]	$ —	$ 1,385	$ —
Drilling rigs [a]	3,822	347	8,917
Fluid storage equipment [a]	—	—	957
Other property, plant and equipment [a]	324	139	—
Impairment of long term contractual agreement [b]	—	—	1,905
Impairment of goodwill [c]	—	—	88
Impairment of intangible [d]	—	—	257
	$ 4,146	$ 1,871	$ 12,124

a. For the years ended December 31, 2017, 2016 and 2015, the Company recognized impairments of $4.1 million, $1.9 million and $9.9 million, respectively, to reduce the carrying value of certain assets which deemed impaired based on future expected cash flows of the equipment. The Company measured impairment using significant unobservable inputs (Level 3) based on an income approach.
b. The Company impaired $1.9 million of assets in 2015 related to prepaid assets pursuant to a purchase contract from a vendor.
c. The Company determined that there was an indication of impairment present based on the results of the first step of the goodwill impairment test for the goodwill held at Energy Services and fully impaired the $0.1 million balance in 2015.
d. The Company terminated one customer relationship related to its amortizable intangible assets and impaired the remaining unamortized value of the intangible of that relationship in 2015.

The assumptions used in the impairment evaluation for long-lived assets are inherently uncertain and require management’s judgment. A continued period of low oil and natural gas prices or continued reductions in capital expenditures by our customers would likely have an adverse impact on our utilization and the prices that we receive for our services. This could result in the recognition of future material impairment charges on the same, or additional, property and equipment if future cash flow estimates, based upon information then available to management, indicate that their carrying values are not recoverable.

6. Goodwill and Intangible Assets

The Company had the following definite lived intangible assets recorded as of the dates presented below (in thousands):

	December 31,	
	2017	2016
Customer relationships	$ 35,795	$ 33,605
Trade names	8,793	7,110
Less: accumulated amortization - customer relationships	(26,172)	(17,655)
Less: accumulated amortization - trade names	(2,277)	(1,493)
Intangible assets, net	$ 16,139	$ 21,567

Amortization expense for intangible assets was $9.3 million, $9.1 million and $9.1 million for the years ended December 31, 2017, 2016, and 2015, respectively. The original life of customer relationships range from 4 to 10 years with a remaining average useful life of 2.36 years. The original life of trade names range from 10 to 20 years useful life and as of December 31, 2017 the remaining useful life was 8.38 years.

Aggregated expected amortization expense for the future periods is expected to be as follows (in thousands):

Year ended December 31:		**Amount**
2018	$	8,578
2019		1,096
2020		1,095
2021		1,090
2022		1,068
Thereafter		3,212
	$	16,139

Goodwill was $99.8 million and $88.7 million at December 31, 2017 and 2016, respectively. Changes in goodwill for the years ended December 31, 2017 and 2016 are set forth below (in thousands):

Balance, January 1, 2016	$	88,727
Additions		—
Balance, December 31, 2016		88,727
Additions - 2017 Stingray Acquisition (Note 14)		10,193
Additions - Higher Power Acquisition (Note 14)		643
Additions - 5 Star Acquisition (Note 14)		248
Balance, December 31, 2017	$	99,811

7. Accrued Expenses and Other Current Liabilities

Accrued expense and other current liabilities included the following (in thousands):

	December 31,			
	2017		**2016**	
Deferred revenue	$	15,210	$	—
Accrued compensation, benefits and related taxes		11,552		2,432
Financed insurance premiums		4,876		3,294
Insurance reserves		2,942		971
State and local taxes payable		2,126		320
Other		4,189		1,529
Total	$	40,895	$	8,546

Financed insurance premiums are due in monthly installments, are unsecured and mature within the twelve-month period following the close of the year. As of December 31, 2017 and 2016, the applicable interest rates associated with financed insurance premiums were 2.75% and 1.97%, respectively.

8. Debt

Mammoth Credit Facility

On November 25, 2014, the Partnership entered into a revolving credit and security agreement with a bank that provides for maximum borrowings of $170.0 million. The facility, as amended in connection with the IPO, matures on November 25, 2019. Borrowings under this facility are secured by the assets of Mammoth Inc., inclusive of the subsidiary companies. The maximum availability of the facility is subject to a borrowing base calculation prepared monthly.

Concurrent with the execution of the facility, the initial advance was used to repay all the debt of the operating subsidiaries then outstanding. Interest is payable monthly at a base rate set by the institution's commercial lending group plus an applicable margin. Additionally, at the Company's request, outstanding balances are permitted to be converted to LIBOR rate plus applicable margin tranches at set increments of $500,000. The LIBOR rate option allows the Company to select interest periods from one, two, three or six months. The applicable margin for either the base rate or the LIBOR rate option can vary from 1.5% to 3.0%, based upon a calculation of the excess availability of the line as a percentage of the maximum credit limit. The deferred loan costs associated with this facility are classified in other non-current assets. The weighted average interest rate for borrowings outstanding under the credit facility as of December 31, 2017 was 4.37%.

At December 31, 2017, there were outstanding borrowings under the credit facility of $99.9 million, leaving an aggregate of $62.8 million of available borrowing capacity under the facility, after giving effect to $6.5 million of outstanding letters of credit. At December 31, 2016, the facility was undrawn and had availability of $146.2 million.

The facility contains various customary affirmative and restrictive covenants. Among the various covenants are specifically identified financial covenants placing requirements of a minimum interest coverage ratio (3.0 to 1.0), maximum leverage ratio (4.0 to 1.0), and minimum availability ($10.0 million). As of December 31, 2017 and 2016, the Company was in compliance with its covenants under the facility.

Sturgeon Credit Facility

On June 30, 2015, Sturgeon entered in to a three-year $25.0 million revolving line of credit secured by substantially all of the assets of Sturgeon ("the Sturgeon revolver"). Advances under the Sturgeon revolver bore interest at 2% plus the greater of (a) the Base Rate as set by the lender's commercial lending group, (b) the sum of the Federal Funds Open Rate plus one half of one percent and (c) the sum of the Daily LIBOR rate. Additionally, at Sturgeon's request, advances could be obtained at LIBOR plus 3%. The LIBOR rate option allowed Sturgeon to select interest periods from one, two, three or six month LIBOR futures spot rates. The Sturgeon revolver was terminated on June 6, 2017. As of December 31, 2016, there were no outstanding borrowings under the Sturgeon revolver, and availability was $18.2 million.

The facility contained various customary affirmative and restrictive covenants. Among the covenants were financial covenants, including a minimum fixed charge coverage ratio (3.5 to 1.0) and a minimum availability block ($5.0 million). The Company was not in compliance with its fixed charge coverage ratio covenant at December 31, 2016, however the Sturgeon revolver was undrawn on that date. The Company was in compliance with all other covenants at December 31, 2016.

9. Other Liabilities

Other liabilities included the following (in thousands):

	December 31,	
	2017	**2016**
Capital lease obligations	$ 2,015	$ 476
Equipment financing arrangement	1,605	—
Taxes	—	2,306
Other	500	—
Total	4,120	2,782
Less: Current portion of capital lease and equipment financing obligations included in accrued expenses and other current liabilities	831	378
Total Other Liabilities	$ 3,289	$ 2,404

The Company leases vehicles and other equipment under capital leases with varying terms and expiration dates through 2020. The weighted average implied interest rate under our capital leases as of December 31, 2017 and 2016 was 19.1% and 5.7%, respectively. Additionally, the Company entered into a five-year equipment financing arrangement maturing in 2022 that bears interest at 4.6% as of December 31, 2017. Principal and interest on capital leases and the equipment financing arrangement are paid monthly. Aggregate future payments under the Company's non-cancelable capital leases and equipment financing arrangement as of December 31, 2017 are as follows (in thousands):

2018	$	1,052
2019		1,565
2020		669
2021		366
2022		360
Total future minimum payments		4,012
Less interest payments		(392)
Present value of future minimum payments	$	3,620

10. Income Taxes

As discussed in Note 1, the Partnership was converted into a limited liability company on October 12, 2016 and the membership interests in the limited liability company were contributed to the Company. As a result, the Company filed a consolidated return for the period October 12, 2016 through December 31, 2016. Prior to the conversion, the Partnership, other than Sand Tiger, was not subject to corporate income taxes.

The components of income tax expense (benefit) attributable to the Company for the year ended December 31, 2017, 2016 and 2015, respectively, are as follows (in thousands):

	Year Ended December 31,					
	2017		2016		2015	
U.S. current income tax expense	$	804	$	2,307	$	13
U.S. deferred income tax (benefit) expense		(27,764)		47,957		(5,626)
Foreign current income tax expense		36,565		3,594		3,879
Foreign deferred income tax (benefit) expense		(6,773)		27		145
Total	$	2,832	$	53,885	$	(1,589)

A reconciliation of the statutory federal income tax amount to the recorded expense is as follows (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Income (loss) before income taxes, as reported	$ 61,796	$ (38,568)	$ (23,409)
Bargain purchase gain, net of tax	(4,012)	—	—
Income (loss) before income taxes, as taxed	57,784	(38,568)	(23,409)
Statutory income tax rate	35%	35%	35%
Expected income tax expense (benefit)	20,224	(13,499)	(8,193)
Income earned as non-taxable entity (See Note 2)	—	15,167	—
Effect due to change to C corporation (See Note 2)	—	53,089	—
Change in entity status	—	—	(4,792)
Non taxable entity	—	—	13,562
Change in tax rate	(21,309)	(25)	—
Tax reform - unrepatriated foreign earnings	(9,727)	—	—
Foreign income tax rate differential	6,286	(1,078)	(1,370)
Foreign earnings not in reported income	22,054	—	—
Foreign tax credits	(29,551)	—	—
Other permanent differences	503	210	—
State tax expenses	39	21	—
Other	(1,192)	—	(796)
Change in valuation allowance	15,505	—	—
Total	$ 2,832	$ 53,885	$ (1,589)

On December 22, 2017, the United States enacted the Tax Act. The Tax Act significantly changes US corporate income tax laws by, among other things, reducing the US corporate income tax rate from 35% to 21% starting in 2018 and creating a territorial tax system with a one-time mandatory tax on previously deferred foreign earnings of US subsidiaries. Under the accounting rules, companies are required to recognize the effects of changes in tax laws and tax rates on deferred tax assets and liabilities in the period in which the new legislation is enacted. The effects of the Tax Act on the Company include (i) remeasurement of deferred taxes and (ii) recognition of liabilities for taxes on mandatory deemed repatriation. As a result of the Tax Act, the Company recorded a credit of $31.0 million during the fourth quarter of 2017. This amount, which is included in Provision (benefit) for income taxes in the Consolidated Statements of Comprehensive Income (Loss), consists of two components: (i) a $21.3 million credit resulting from the remeasurement of the Company's net deferred tax liabilities in the US based on the new lower corporate income tax rate, and (ii) a $9.7 million credit related to a reversal of deferred liabilities for unrepatriated foreign earnings.

The SEC staff issued Staff Accounting Bulletin No. 118 in December 2017, which allows registrants to record provisional amounts for effects of the Tax Act during a one-year measurement period. The Company has completed its accounting for the re-measurement of deferred taxes from the previous rate of 35% to the new rate of 21%. As not all of the necessary information to analyze all income tax effects of the Tax Act related to the recognition of liabilities for taxes on mandatory repatriation is currently available, the amounts recorded related to deemed repatriation of Sand Tiger's earnings in Canada are provisional amounts, which are believed represents a reasonable estimate of the accounting implications of this tax reform. The Company will continue to evaluate the Tax Act and adjust the provisional amounts as additional information is obtained. The ultimate impact of tax reform may differ from the provisional amounts due to changes in interpretations and assumptions, as well as additional regulatory guidance that may be issued. The Company expects to complete its detailed analysis no later than the fourth quarter of 2018.

Deferred tax liabilities attributable to the Company consisted of the following (in thousands):

	Year Ended December 31, 2017	Year Ended December 31, 2016
Deferred tax assets:		
Allowance for doubtful accounts	$ 11,973	$ 1,893
Deferred compensation	1,032	1,687
Accrued liabilities	1,442	601
Foreign tax credits	15,505	145
Other	1,448	1,786
Valuation allowance	(15,505)	—
Deferred tax assets	15,895	6,112
Deferred tax liabilities:		
Property and equipment	$ (40,390)	$ (42,526)
Intangible assets	(2,839)	(7,663)
Unrepatriated foreign earnings	—	(3,451)
Other	(74)	(143)
Deferred tax liabilities	(43,303)	(53,783)
Net deferred tax liability	$ (27,408)	$ (47,671)
Reflected in accompanying balance sheet as:		
Deferred income tax asset	$ 6,739	$ —
Deferred income tax liability	(34,147)	(47,671)
Total	$ (27,408)	$ (47,671)

During the year ended December 31, 2017, the Company recorded a valuation allowance of $15.5 million related to foreign tax credits that are not expected to be utilized.

11. Earnings (Loss) Per Share

Loss Per Unit

The Partnership's limited partner units were issued November 24, 2014. However, the net income (loss) per common unit on the Consolidated Statements of Comprehensive Income (Loss) is based on the net income (loss) of the Partnership for the full years presented, since the entities were under common control as described in Note 1.

The Partnership's net loss was allocated wholly to the limited partner units as the General Partner did not have an economic interest.

Basic net loss per common unit is calculated by dividing net loss by the weighted-average number of common units outstanding during the period.

	2015
Net loss	$ (21,820)
Net loss per limited partner unit	(0.73)
Weighted-average common units outstanding	30,000

Common Stock Offering

On October 14, 2016, Mammoth Inc.'s common stock began trading on The Nasdaq Global Select Market under the symbol "TUSK." On October 19, 2016, the Company closed the IPO of 7,750,000 shares of common stock at $15.00 per share. Net proceeds to Mammoth Inc. from its sale of 7,500,000 shares of common stock were approximately $103.1 million.

The authorized capital stock of the Company consists of 200 million shares of common stock, par value $0.01 per share.

Earnings (Loss) Per Share

The number of common shares outstanding on a fully-converted basis was the same before and after any conversion of our owner units. Each time one common share was issued upon conversion of investor units, the number of common shares went up by one, and the number of common units outstanding that were convertible went down by one. Accordingly, for the year ended December 31, 2015, there was no difference between common stock basic and diluted earnings per share because the conversion of common units into common shares did not impact the number of common shares on a fully-converted basis.

Year Ended December 31,	Weighted Average Shares Outstanding	Share Issuance at IPO [(a)]	Conversion	Weighted Average Units Outstanding
2016	31,500,000	1,500,000	(30,000,000)	30,000,000
2015	30,000,000	—	(30,000,000)	30,000,000

(a) Weighted average of 7,500,000 shares issued from the closing date of the IPO on October 19, 2016 to December 31, 2016.

	Year Ended December 31,		
	2017	2016	2015
	(in thousands, except per share data)		
Basic earnings (loss) per share:			
Allocation of earnings:			
Net income (loss)	$ 58,964	$ (92,453)	$ (21,820)
Weighted average common shares outstanding	41,548	31,500	30,000
Basic earnings (loss) per share	$ 1.42	$ (2.94)	$ (0.73)
Diluted earnings (loss) per share:			
Allocation of earnings:			
Net income (loss)	$ 58,964	$ (92,453)	$ (21,820)
Weighted average common shares, including dilutive effect [(a)]	41,639	31,500	30,000
Diluted earnings (loss) per share	$ 1.42	$ (2.94)	$ (0.73)

(a) No incremental shares of potentially dilutive restricted stock awards were included for the years ended December 31, 2016 or 2015 as their effect was antidilutive under the treasury stock method.

Unaudited Pro Forma Loss Per Share

The Company's pro forma basic loss per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period, as if the common shares issued upon the conversion to Mammoth Inc. were outstanding for the entire year. A reconciliation of the components of pro forma basic and diluted loss per common share is presented in the table below:

	Year Ended December 31, 2016	2015
	(in thousands, except per share data)	
Pro Forma C Corporation Data (unaudited):		
Net loss, as reported	$ (92,453)	$ (21,820)
Taxes on income earned as a non-taxable entity (Note 10)	15,224	391
Taxes due to change to C corporation (Note 10)	53,089	—
Pro forma net loss	$ (24,140)	$ (21,429)
Basic loss per share:		
Allocation of earnings:		
Net loss	$ (24,140)	$ (21,429)
Weighted average common shares outstanding	43,107	43,107
Basic loss per share	$ (0.56)	$ (0.50)
Diluted loss per share:		
Allocation of earnings:		
Net loss	$ (24,140)	$ (21,429)
Weighted average common shares, including dilutive effect [a]	43,107	43,107
Diluted loss per share	$ (0.56)	$ (0.50)

(a) No incremental shares of potentially dilutive restricted stock awards were included for periods presented as their effect was antidilutive under the treasury stock method.

Pro forma basic and diluted loss per share has been computed by dividing pro forma net loss attributable to the Company by the number of shares of common stock determined as if the shares of common stock issued were outstanding for all periods presented. Management believes that these assumptions provide a reasonable basis for presenting the pro forma effects.

12. Equity Based Compensation

Upon formation of certain Operating Entities (including the acquired Stingray Entities), specified members of management ("Specified Members") were granted the right to receive distributions from their respective Operating Entity, after the contribution member's unreturned capital balance was recovered (referred to as "Payout" provision). Additionally, non-employee members were included in the award class ("Non-Employee Members").

On November 24, 2014, the awards were modified in conjunction with the contribution of the Operating Entities to the Partnership. Awards are not granted in limited or general partner units. Agreements are for interests in the distributable earnings of Mammoth Holdings, Mammoth's then majority limited partner unit holder.

On the IPO closing date, Mammoth Holding's unreturned capital balance was not fully recovered from its sale of common stock in the IPO. As a result, Payout did not occur and no compensation cost was recorded. Future offerings or sales of common stock that will recover outstanding unreturned capital remain not probable.

Payout is expected to occur following the sale by Mammoth Holding's of its shares of the Company's common stock, which is considered not probable until the event occurs. Therefore, for the awards that contained the Payout provision, no compensation cost was recognized as the distribution rights do not vest until Payout is reached. For the Specified Member awards, the unrecognized amount, which represents the fair value of the award as of the modification dates or grant date, was $5.6 million. For the Non-Employees Member awards, the unrecognized cost, which represents the fair value of the awards as of December 31, 2017, was $51.7 million.

13. Stock-Based Compensation

The 2016 Plan authorizes the Company's Board of Directors or the compensation committee of the Company's Board of Directors to grant incentive restricted stock, restricted stock unit, stock appreciation rights, stock options and performance awards. There are 4.5 million shares of common stock reserved for issuance under the 2016 Plan.

Restricted Stock Units

The fair value of restricted stock unit awards was determined based on the fair market value of the Company's common stock on the date of the grant. This value is amortized over the vesting period. Forfeitures are recognized as they occur.

A summary of the status and changes of the unvested shares of restricted stock units under the 2016 Plan is presented below.

	Number of Unvested Restricted Stock Units		Weighted Average Grant-Date Fair Value
Unvested restricted stock units as of October 19, 2016	—	$	—
Granted	298,335	$	14.97
Vested	(11,110)	$	(14.69)
Forfeited	(4,445)	$	(15.00)
Unvested restricted stock units as of December 31, 2016	282,780	$	14.98
Granted	460,185	$	20.72
Vested	(97,890)	$	(15.07)
Forfeited	(4,443)	$	(15.00)
Unvested restricted stock units as of December 31, 2017	640,632	$	19.44

As of December 31, 2017, there was $9.6 million of total unrecognized compensation cost related to the unvested restricted stock. The cost is expected to be recognized over a weighted average period of approximately twenty-six months.

Included in cost of revenue and selling, general and administrative expenses is stock-based compensation expense of $3.7 million and $0.5 million, respectively, for the years ended December 31, 2017 and 2016.

14. Acquisitions

(a) Description of Stingray Acquisition

On March 20, 2017, and as amended on May 12, 2017, the Company entered into two definitive contribution agreements, one such agreement with MEH Sub LLC ("MEH Sub"), Wexford Offshore Stingray Energy Corp., Gulfport and Mammoth LLC and the other with MEH Sub, Wexford Offshore Stingray Pressure Pumping Corp., Gulfport and Mammoth LLC (collectively, the "Stingray Contribution Agreements"). Under the Stingray Contribution Agreements, the Company agreed to acquire all outstanding membership interests, through its wholly-owned subsidiary Mammoth LLC, in Cementing and SR Energy (the "2017 Stingray Acquisition"). The addition of their water transfer, equipment rentals and cementing services further expanded and vertically integrated Mammoth's service offerings.

The 2017 Stingray Acquisition closed on June 5, 2017. Pursuant to the Stingray Contribution Agreements, Mammoth issued 1,392,548 shares of its common stock, par value $0.01 per share, for all outstanding equity interests in SR Energy and Cementing. Based upon a closing price of Mammoth's common stock of $18.50 per share on June 5, 2017, the total purchase price was $25.8 million.

At the acquisition date, the components of the consideration transferred were as follows (in thousands):

Consideration attributable to Cementing [(1)]	$	12,975
Consideration attributable to SR Energy [(1)]		12,787
Total consideration transferred	$	25,762

(1) See summary of acquired assets and liabilities below

		SR Energy		Cementing		Total
				(in thousands)		
Cash and cash equivalents	$	1,611	$	1,060	$	2,671
Accounts receivable, net		3,913		495		4,408
Receivables from related parties		3,684		1,418		5,102
Inventories		—		306		306
Prepaid expenses		35		32		67
Property, plant and equipment[(1)]		13,061		7,459		20,520
Identifiable intangible assets - customer relationships[(2)]		—		1,140		1,140
Identifiable intangible assets - trade names[(2)]		550		270		820
Goodwill[(3)]		3,929		6,264		10,193
Other assets		7		—		7
Total assets acquired	$	26,790	$	18,444	$	45,234
Accounts payable and accrued liabilities	$	5,890	$	2,063	$	7,953
Long-term debt [(4)]		5,074		2,000		7,074
Deferred tax liability		3,039		1,406		4,445
Total liabilities assumed	$	14,003	$	5,469	$	19,472
Net assets acquired	$	12,787	$	12,975	$	25,762

(1) Property, plant and equipment fair value measurements were prepared by utilizing a combined fair market value and cost approach. The market approach relies on comparability of assets using market data information. The cost approach places emphasis on the physical components and characteristics of the asset. It places reliance on estimated replacement cost, depreciation and economic obsolescence.

(2) Identifiable intangible assets were measured using a combination of income approaches. Trade names were valued using a "relief-from-Royalty" method. Non-contractual customer relationships were valued using a "multi-period excess earnings" method. Identifiable intangible assets will be amortized over 5-10 years.

(3) Goodwill was the excess of the consideration transferred over the net assets recognized and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized. Goodwill recorded in connection with the acquisition is attributable to assembled workforces and future profitability based on the synergies expected to arise from the acquired entities.

(4) Long-term debt assumed was paid off subsequent to the acquisition.

Since the acquisition date, the businesses acquired have provided the following activity (in thousands):

	2017			
		SR Energy		Cementing
Revenues[(a)]	$	11,572	$	7,500
Net loss[(b)]		(1,626)		(1,963)

a. Includes $0.6 million and a nominal amount in intercompany revenues for SR Energy and Cementing, respectively.
b. Includes $3.4 million and $4.1 million in depreciation and amortization for SR Energy and Cementing, respectively.

The following table presents unaudited pro forma information as if the acquisition of SR Energy and Cementing had occurred on January 1, 2016 (in thousands):

	Year Ended December 31, 2017	2016
Revenues[(a)]	$ 35,142	$ 23,659
Net loss	(4,066)	(8,171)

a. Includes $1.0 million and $0.7 million, respectively, in intercompany and related party revenues for SR Energy and Cementing for the years ended December 31, 2017 and 2016.

The historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the 2017 Stingray Acquisition. For the year ended December 31, 2017, there were $0.2 million transaction related costs expensed. The unaudited pro forma consolidated results are not necessarily indicative of what the consolidated results of operations actually would have been had the 2017 Stingray Acquisition been completed on January 1, 2017. In addition, the unaudited pro forma consolidated results do not purport to project the future results of operations of the Company.

(b) Description of Chieftain Acquisition

On March 27, 2017, as amended as of May 24, 2017, the Company entered into a Purchase Agreement with the Chieftain Sellers, following the Company's successful bid in a bankruptcy court auction for substantially all of the assets of the Chieftain Sellers (the "Chieftain Assets"). The Chieftain Acquisition closed on May 26, 2017. Mammoth funded the purchase price for the Chieftain Assets with cash on hand and borrowings under its revolving credit facility. The Chieftain Assets are held by the Company's wholly owned subsidiary Piranha and are included in the Company's sand segment. The Chieftain Acquisition added sand reserves, increased our production capacity and provided access to the Union Pacific railroad, which affords access to both the Mid-Continent basin in support of the Company’s pressure pumping services as well as the Permian basin.

On the acquisition date, the $36.3 million in cash consideration consisted of the following components (in thousands):

	Total
Property, plant and equipment [(1)]	$ 23,373
Sand reserves [(2)]	20,910
Total assets acquired	$ 44,283
Asset retirement obligation	1,732
Total liabilities assumed	$ 1,732
Total allocation of purchase price	$ 42,551
Bargain purchase price [(3, 4)]	(6,231)
Total purchase price	$ 36,320

(1) Property, plant and equipment fair value measurements were prepared by utilizing a combined fair market value and cost approach. The market approach relies on comparability of assets using market data information. The cost approach places emphasis on the physical components and characteristics of the asset. It places reliance on estimated replacement cost, depreciation and economic obsolescence.

(2) The fair value of the sand reserves was determined based on the excess cash flow method, a form of the income approach. The method provides a value based on the estimated remaining life of sand reserves, projected financial information and industry projections.

(3) Amount in Consolidated Statements of Comprehensive Income (Loss) reflected net of income taxes of $2.2 million.

(4) The fair value of the business was determined based on the excess cash flow method, a form of the income approach.

Since the acquisition date, the Chieftain Assets have provided the following activity (in thousands):

	2017 Piranha
Revenues[(a)]	$ 22,847
Net income[(b)]	5,520

a. Includes $12.3 million in intercompany revenues
b. Includes $2.8 million in depreciation and amortization

The following table presents unaudited pro forma information as if the acquisition of the Chieftain Assets had occurred as of January 1, 2016 (in thousands):

	Year Ended December 31,	
	2017	2016
Revenues[a]	$ 22,847	$ 7,690
Net income	5,655	34,127

a. Includes $12.3 million in intercompany revenues for 2017

The Company's historical financial information was adjusted to give pro forma effect to the events that were directly attributable to the Chieftain Acquisition. For the year ended December 31, 2017, $0.8 million of transaction related costs were expensed.

(c) Description of Sturgeon Acquisition

On March 20, 2017, and as amended on May 12, 2017, the Company entered into a definitive contribution agreement with MEH Sub, Wexford Offshore Sturgeon Corp., Gulfport, Rhino and Mammoth Energy Partners LLC (the “Sturgeon Contribution Agreement”). Under the Sturgeon Contribution Agreement, the Company agreed to acquire all outstanding membership interests, through its wholly-owned subsidiary Mammoth LLC, in Sturgeon, which owns all of the membership interests in Taylor Frac, Taylor RE and South River (collectively, the "Sturgeon subsidiaries"). The acquisition added sand reserves, increased our production capacity and provided access to the Canadian National Railway, which affords access to the Appalachian basin in support of the Company’s pressure pumping services as well as to western Canada.

The acquisition of Sturgeon closed on June 5, 2017. Pursuant to the Sturgeon Contribution Agreement, Mammoth issued 5,607,452 shares of its common stock, par value $0.01 per share, for all outstanding equity interests in Sturgeon. Based upon a closing price of Mammoth's common stock of $18.50 per share on June 5, 2017, the total purchase price was $103.7 million.

As a result of this transaction, the Company's historical financial information has been recast to combine the Consolidated Statements of Comprehensive Income (Loss) and the Consolidated Balance Sheets of the Company for all periods included in the accompanying financial statements with those of Sturgeon as if the combination had been in effect since Sturgeon commenced operations on September 13, 2014. Any material transactions between the Company and Sturgeon were eliminated. Sturgeon's financial results were incorporated into the Company's natural sand proppant services division.

For the year ended December 31, 2017, $1.3 million of transaction related costs were expensed.

(d) Acquisition of Higher Power

On April 21, 2017, the Company completed its acquisition of Higher Power for total consideration of $4.0 million, including $3.3 million in cash to the sellers plus $0.8 million in consideration to be paid in equal annual installments over the next three years. As of December 31, 2017, $0.3 million and $0.5 million, respectively, of the consideration are reflected in the accrued expenses and other current liabilities and other liabilities. Mammoth funded the purchase price for Higher Power with cash on hand and borrowings under its credit facility. The acquisition of Higher Power added an energy infrastructure component to the Company's other energy services segment, helping to diversify its service offerings.

For the year ended December 31, 2017, there were $0.1 million of transaction related costs expensed.

The following table summarizes the fair value of Higher Power as of April 21, 2017 (in thousands):

		Higher Power
Property, plant and equipment	$	1,744
Identifiable intangible assets - customer relationships		1,613
Goodwill (1)		643
Total assets acquired	$	4,000

(1) Goodwill was the excess of the consideration transferred over the net assets recognized and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized. Goodwill recorded in connection with the acquisition is attributable to assembled workforces and future profitability expected to arise from the acquired entity.

From its acquisition date through December 31, 2017, Higher Power has provided the following activity (in thousands):

		2017 Higher Power
Revenues(a)	$	39,571
Net income (b)		5,127

a. Includes $27.4 million in intercompany revenues
b. Includes $2.0 million in depreciation and amortization

The following table presents unaudited pro forma information as if the acquisition of Higher Power had occurred as of January 1, 2016 (in thousands):

	Year Ended December 31,			
	2017		2016	
Revenues(a)	$	42,343	$	10,039
Net income (loss)		5,004		(1,189)

a. Includes $27.4 million in intercompany revenues for 2017

(e) Acquisition of 5 Star

On July 1, 2017, the Company completed its acquisition of 5 Star for total consideration of $2.4 million in cash to the sellers. Mammoth funded the purchase price for 5 Star with cash on hand and borrowings under its credit facility. The acquisition of 5 Star added to the infrastructure component of the Company's other energy services segment and provided expansion of the infrastructure segment into the eastern United States.

For the year ended December 31, 2017, there were $0.1 million of transaction related costs expensed.

The following table summarizes the fair value of 5 Star as of July 1, 2017 (in thousands):

		5 Star
Accounts receivable	$	2,440
Property, plant and equipment		1,863
Identifiable intangible assets - trade names (1)		300
Goodwill (2)		248
Total assets acquired	$	4,851
Long-term debt and other liabilities	$	2,413
Total liabilities assumed	$	2,413
Net assets acquired	$	2,438

(1) Identifiable intangible assets were measured using a combination of income approaches. Trade names were valued using a "Relief-from-Royalty" method. Non-contractual customer relationships were valued using a "Multi-period excess earnings" method. Identifiable intangible assets will be amortized over 5-10 years.

(2) Goodwill was the excess of the consideration transferred over the net assets recognized and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized. Goodwill recorded in connection with the acquisition is attributable to assembled workforces and future profitability expected to arise from the acquired entity.

From its acquisition date through December 31, 2017, 5 Star has provided the following activity (in thousands):

	2017
	5 Star
Revenues[a]	$ 25,216
Net income [b]	4,191

a. Includes $16.0 million in intercompany revenues
b. Includes $0.8 million in depreciation and amortization

The following table presents unaudited pro forma information as if the acquisition of 5 Star had occurred as of January 1, 2016 (in thousands):

	Year Ended December 31,	
	2017	2016
Revenues[a]	$ 31,548	$ 13,971
Net income (loss)	3,910	(839)

a. Includes $16.0 million in intercompany revenues for 2017

15. Related Party Transactions

Transactions between the subsidiaries of the Company and the following companies are included in Related Party Transactions: Gulfport; Grizzly Oil Sands ULC (“Grizzly”); El Toro Resources LLC ("El Toro"); Diamondback E&P, LLC ("Diamondback"); Cementing and SR Energy (collectively, prior to the 2017 Stingray Acquisition, the "2017 Stingray Companies"); Everest Operations Management LLC ("Everest"); Elk City Yard LLC ("Elk City Yard"); Double Barrel Downhole Technologies LLC ("DBDHT"); Orange Leaf Holdings LLC ("Orange Leaf"); Caliber Investment Group LLC ("Caliber"); Dunvegan North Oilfield Services ULC (“Dunvegan”); Predator Drilling LLC ("Predator"); and T&E Flow Services LLC ("T&E").

Following is a summary of related party transactions (in thousands):

		REVENUES			ACCOUNTS RECEIVABLE	
		Years Ended December 31,			At December 31,	
		2017	2016	2015	2017	2016
Pressure Pumping and Gulfport	(a)	$ 144,473	$ 102,390	$ 124,311	$ 25,054	$ 19,095
Muskie and Gulfport	(b)	42,956	25,783	38,182	1,947	5,373
Panther and Gulfport	(c)	3,253	3,011	3,703	872	1,434
Redback Energy and Gulfport	(d)	—	—	2,549	—	—
Cementing and Gulfport	(e)	7,410	—	—	2,255	—
SR Energy and Gulfport	(f)	10,129	—	—	3,348	—
Bison Drilling and El Toro	(g)	—	372	521	—	—
Panther and El Toro	(g)	96	172	192	—	—
Bison Trucking and El Toro	(g)	—	130	145	—	—
Redback Energy and El Toro	(h)	216	530	168	—	108
Coil Tubing and El Toro	(i)	161	319	—	—	—
Bison Drilling and Predator	(j)	234	—	—	234	—
The Company and 2017 Stingray Companies	(k)	63	38	9	—	1,363
Other Relationships		29	185	955	78	216
		$ 209,020	$ 132,930	$ 170,735	$ 33,788	$ 27,589

a. Pressure Pumping provides pressure pumping, stimulation and related completion services to Gulfport.
b. Muskie has agreed to sell and deliver, and Gulfport has agreed to purchase, specified annual and monthly amounts of natural sand proppant, subject to certain exceptions specified in the agreement, and pay certain costs and expenses.
c. Panther performs drilling services for Gulfport pursuant to a master service agreement.
d. Redback Energy performs completion and production services for Gulfport pursuant to a master service agreement.
e. Cementing performs well cementing services for Gulfport.
f. SR Energy performs well cementing services for Gulfport.
g. The contract land and directional drilling segment provides services for El Toro, an affiliate of Wexford, pursuant to a master service agreement.
h. Redback Energy performs completion and production services for El Toro pursuant to a master service agreement.
i. Coil Tubing provides El Toro services in connection with completion activities.
j. Bison Drilling provides equipment rentals to Predator, an entity in which Wexford owns a minority interest.
k. The Company provided certain services to the 2017 Stingray Companies.

		COST OF REVENUE			ACCOUNTS PAYABLE	
		Years Ended December 31,			At December 31,	
		2017	2016	2015	2017	2016
Cobra and T&E	(a)	610	—	—	457	—
Higher Power and T&E	(a)	25	—	—	3	—
Panther and DBDHT	(b)	196	49	101	77	—
Redback Energy and Elk City Yard	(c)	71	107	107	—	—
The Company and 2017 Stingray Companies	(d)	432	724	933	—	174
Other Relationships		74	186	238	218	3
		$ 1,408	$ 1,066	$ 1,379	$ 755	$ 177
		SELLING, GENERAL AND ADMINISTRATIVE COSTS				
Consolidated and Everest	(e)	$ 175	$ 262	$ 493	$ 19	$ 13
Consolidated and Wexford	(f)	892	394	384	150	13
Mammoth and Orange Leaf	(g)	46	102	50	—	—
Mammoth and Caliber	(h)	335	—	24	1	—
Other Relationships		33	—	—	2	—
		$ 1,481	$ 758	$ 951	$ 172	$ 26
		CAPITAL EXPENDITURES				
Cobra and T&E	(a)	629	—	—	66	—
Higher Power and T&E	(a)	1,380	—	—	385	—
		$ 2,009	$ —	$ —	$ 451	$ —
					$ 1,378	$ 203

a. Cobra and Higher Power purchase materials and services from T&E, an entity in which a member of management's family owns a minority interest.
b. Panther rents rotary steerable equipment in connection with its directional drilling services from DBDHT, an affiliate of Wexford.
c. Redback Energy leases property from Elk City Yard, an affiliate of Wexford.
d. Prior to the 2017 Stingray Acquisition, the 2017 Stingray Companies provided certain services to the Company and, from time to time, the 2017 Stingray Companies paid for goods and services on behalf of the Company.
e. Everest, a subsidiary of Wexford, has historically provided office space and certain technical, administrative and payroll services to the Company and the Company has reimbursed Everest in amounts determined by Everest based on estimates of the amount of office space provided and the amount of employees' time spent performing services for the Company.
f. Wexford provides certain administrative and analytical services to the Company and, from time to time, the Company pays for goods and services on behalf of Wexford.
g. Mammoth subleased office space from Orange Leaf, an entity in which a member of management and a member of management's family own, in the aggregate, a minority interest. The sublease was terminated in May 2017.
h. Mammoth leases office space from Caliber, an entity controlled by Wexford.

16. Commitments and Contingencies

Lease Obligations

The Company leases real estate, rail cars and other equipment under long-term operating leases with varying terms and expiration dates through 2062.

Minimum Purchase Commitments

The Company has entered into agreements with suppliers that contain minimum purchase obligations. Failure to purchase the minimum amounts may require the Company to pay shortfall fees. However, the minimum quantities set forth in the agreements are not in excess of currently expected future requirements.

Capital Spend Commitments

The Company has entered into agreements with suppliers to acquire capital equipment.

Aggregate future minimum payments under the Company's non-cancelable operating, capital spend commitments and minimum purchase commitments as of December 31, 2017 are as follows (in thousands):

Year ended December 31:	Operating Leases	Capital Spend Commitments	Minimum Purchase Commitments
2018	$ 20,407	$ 19,582	$ 32,222
2019	14,200	—	10,866
2020	11,864	—	—
2021	9,303	—	—
2022	6,515	—	—
Thereafter	3,345	—	—
	$ 65,634	$ 19,582	$ 43,088

For the years ended December 31, 2017, 2016 and 2015, the Company recognized rent expense of $11.4 million, $8.2 million and $8.5 million, respectively.

The Company has various letters of credit that were issued under the Company's revolving credit agreement which is collateralized by substantially all of the assets of the Company. The letters of credit are categorized below (in thousands):

	December 31, 2017	December 31, 2016
Environmental remediation	$ 3,582	$ 1,375
Insurance programs	2,486	1,636
Rail car commitments	455	455
Total letters of credit	$ 6,523	$ 3,466

The Company has insurance coverage for physical partial loss to its 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. As of December 31, 2017 and 2016, the policy requires a deductible per occurrence of $0.3 million for workers' compensation and $0.1 million for auto claims. The Company establishes liabilities for the unpaid deductible portion of claims incurred relating to workers’ compensation and auto liability based on estimates. As of December 31, 2017 and 2016, the policies contained an aggregate stop loss of $2.0 million. The Company also self-insures its employee health insurance. The Company has coverage on its self-insurance program in the form of a stop loss of $0.2 million per participant and an aggregate stop-loss of $5.8 million for the calendar year ending December 31, 2017. As of December 31, 2017 and 2016, accrued claims were $2.9 million and $1.0 million, respectively. These estimates may change in the near term as actual claims continue to develop.

Pursuant to certain customer contracts in our infrastructure services segment, the Company warrants equipment and labor performed under the contracts for a specified period following substantial completion of the work. Generally, the warranty is for one year or less. No liabilities were accrued as of December 31, 2017 or 2016 and no expense was recognized during the years ended December 31, 2017, 2016 or 2015 related to warranty claims. However, if warranty claims occur, the Company could be required to repair or replace warrantied items, which in most cases are covered by warranties extended from the manufacturer of the equipment. In the event the manufacturer of equipment failed to perform on a warranty obligation or denied a warranty claim made by the Company, the Company could be required to pay for the cost of the repair or replacement.

The Company is routinely involved in state and local tax audits. During 2015, the State of Ohio assessed taxes on the purchase of equipment the Company believes is exempt under state law. The Company appealed the assessment and a hearing was held in 2017. As a result of the hearing, the Company received a decision from the State of Ohio. The Company is appealing the decision and while it is not able to predict the outcome of the appeal, this matter is not expected to have a material adverse effect on the Company's financial position, results of operations or cash flows.

On June 3, 2015, a putative class and collective action lawsuit alleging that Pressure Pumping failed to pay a class of workers overtime in compliance with the Fair Labor Standards Act and Ohio law was filed titled William Crigler, et al v. Stingray Pressure Pumping, LLC in the U.S. District Court Southern District of Ohio Eastern Division. The parties reached a settlement of this matter which received final approval from the court in August 2017. This settlement was paid in 2017 and did not have a material impact on the Company’s financial position, results of operations or cash flows.

On December 2, 2015, a putative class and collective action lawsuit alleging that Bison Drilling failed to pay a class of workers overtime in compliance with the Fair Labor Standards Act and Texas law was filed titled John Talamantez, individually and on behalf of all others similarly situated v. Bison Drilling and Field Services, LLC in the U.S. District Court Western District of Texas Midland/Odessa Division. The parties reached a settlement of this matter in October 2017. The settlement was paid in 2017 and did not have a material impact on the Company's financial position, results of operations or cash flows.

On June 22, 2016, a putative, Title VII discrimination, and Oklahoma anti-discrimination lawsuit alleging that Redback Energy Services was in violation of the previously mentioned federal and state laws. The lawsuit was filed titled Earl Richardson and Keary Johnson v. Redback Energy Services LLC in the U.S. District Court for the Western District of Oklahoma. The parties reached a settlement of this matter in August 2017. This settlement was paid in 2017 and did not have a material impact on the Company’s financial position, results of operations or cash flows.

On August 1, 2016, a putative class and collective action lawsuit alleging that Energy Services failed to pay a class of workers overtime in compliance with the Fair Labor Standards Act and Texas law was filed titled Michael Caffey, individually and on behalf of all others similarly situated v. Redback Energy Services LLC in the U.S. District Court for the Western District of Texas. The Company is evaluating the background facts and at this time is not able to predict the outcome of this lawsuit or whether it will have a material impact on the Company’s financial position, results of operations or cash flows.

On September 27, 2016, a putative lawsuit alleging that Energy Services failed to pay a class of workers in compliance with the Fair Labor Standards Act was filed titled Michael Drake vs. Redback Coil Tubing LLC, et al in the U.S. District Court Western District of Texas. The parties reached a settlement of this matter in November 2017. This settlement was paid in 2017 and did not have a material impact on the Company’s financial position, results of operations or cash flows.

On January 26, 2017, a collective action lawsuit alleging that Pressure Pumping failed to pay a class of workers in compliance with the Fair Labor Standards Act was filed titled Ryan Crosby vs. Stingray Pressure Pumping, in the United Stated District Court for the Southern District of Ohio Eastern Division. The Company is evaluating the background facts at this time and is not able to predict the outcome of this lawsuit or whether it will have a material impact on the Company’s financial position, results of operations or cash flows.

On June 27, 2017, a complaint alleging negligence, as a result of a motor vehicle accident, was filed titled Donnelle Banks, individually and as parent and next Friend for Leila Ann Hollis, a minor, vs. Redback Coil Tubing LLC and Mammoth Energy Services, Inc. in the District Court of Gregg County, Texas. The Company is evaluating the background facts and at this time is not able to predict the outcome of this lawsuit or whether it will have a material impact on the Company’s financial position, results of operations or cash flows.

The Company is involved in various other legal proceedings in the ordinary course of business. Although the Company cannot predict the outcome of these proceedings, legal matters are subject to inherent uncertainties and there exists the possibility that the ultimate resolution of these matters could have a material adverse effect on the Company's business, financial condition, results of operations or cash flows.

Defined contribution plan

The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees at their date of hire. The plan allows eligible employees to contribute up to 92% of their annual compensation, not to exceed annual limits established by the federal government. The Company makes discretionary matching contributions of up to 3% of an employee's compensation and may make additional discretionary contributions for eligible employees. The Company did not pay any contributions for the year ended December 31, 2017. For the years ended December 31, 2016 and 2015 the Company paid $0.1 million and $1.5 million, respectively, in contributions to the plan. Effective January 1, 2018, the Company reinstated matching contributions of up to 3% of eligible employee's compensation.

17. Reporting Segments and Geographic Areas

Reporting Segments

As of December 31, 2017, our revenues, income before income taxes and identifiable assets are primarily attributable to four reportable segments. The Company principally provides energy services in connection with on-shore drilling of oil and natural gas wells for small to large domestic independent oil and natural gas producers and electric infrastructure services to government-funded utilities, private utilities, public investor-owned utilities and co-operative utilities.

The Company's Chief Executive Officer and Chief Financial Officer comprise the Company's Chief Operating Decision Maker function ("CODM"). Segment information is prepared on the same basis that the CODM manages the segments, evaluates the segment financial statements, and makes key operating and resource utilization decisions. Segment evaluation is determined on a quantitative basis based on a function of operating income (loss), as well as a qualitative basis, such as nature of the product and service offerings and types of customers.

Prior to 2017, the Company had five reportable segments, including pressure pumping services, well services, natural sand proppant services, contract land and directional drilling services and other energy services. Based on the CODM's assessment at December 31, 2017, the Company changed its reportable segment presentation in 2017, as it no longer considers well services, which previously included Redback Energy Services, Redback Coil Tubing and Mammoth Energy Partners, and other energy services, which previously included Sand Tiger, to be significant to the understanding of results. The Company now presents the results of its well service and other energy service business in a reconciling column titled "All Other" in the year ended December 31, 2017 table below. Additionally, during 2017, the Company added a new reportable segment for its infrastructure service activities. As of December 31, 2017, the Company's four reportable segments include pressure pumping services ("Pressure Pumping"), infrastructure services ("Infrastructure"), natural sand proppant services ("Sand") and contract land and directional drilling services ("Drilling"). The results for the years ended December 31, 2016 and 2015 continue to be reported under the five segments identified above, and therefore, are not directly comparable to the results for the year ended December 31, 2017.

The pressure pumping services segment provides hydraulic fracturing services primarily in the Utica Shale of Eastern Ohio, Marcellus Shale in Pennsylvania, Eagle Ford and Permian Basins in Texas and the mid-continent region. The infrastructure services segment provides electric utility infrastructure services to government-funded utilities, private utilities, public investor-owned utilities and co-operative utilities in Puerto Rico and the northeast, southwest and midwest portions of the United States. The sand segment mines, processes and sells sand for use in hydraulic fracturing. The sand segment primarily services the Utica Shale, Permian Basin, SCOOP, STACK and Montney Shale in British Columbia and Alberta, Canada. The contract land and directional drilling services segment provides vertical, horizontal and directional drilling services in the Permian Basin in West Texas. The Company also provides coil tubing services, pressure control services, flowback services, cementing services, equipment rental services and remote accommodation services.

Prior to 2017, information used by the CODM in measuring segment profits or losses did not include intersegment revenues and costs as they were deemed immaterial for decision-making purposes. In 2017, the Company's CODM changed the way segment profits and losses are measured to include intersegment revenues and expenses. The historical results by segment below for the years ended December 31, 2016 and 2015 have been revised to reflect this change in measurement method.

Sales from one segment to another are generally priced at estimated equivalent commercial selling prices. Amounts included in the Eliminations column in the following tables include intersegment transactions conducted between reportable segments that are eliminated in consolidation. Transactions conducted by companies within the same reporting segment are eliminated within each reporting segment. The following tables set forth certain financial information with respect to the Company's reportable segments (in thousands):

Year Ended December 31, 2017	Pressure Pumping	Infrastructure	Sand	Drilling	All Other[(a)]	Eliminations	Total
Revenue from external customers	$ 277,326	$ 224,425	$ 90,023	$ 50,075	$ 49,647	$ —	$ 691,496
Intersegment revenues	2,026	—	27,014	446	2,081	(31,567)	—
Total revenue	279,352	224,425	117,037	50,521	51,728	(31,567)	691,496
Cost of revenue, exclusive of depreciation, depletion, amortization and accretion	183,089	120,117	91,049	46,701	41,613	—	482,569
Intersegment cost of revenues	28,147	1,443	1,731	146	65	(31,532)	—
Total cost of revenue	211,236	121,560	92,780	46,847	41,678	(31,532)	482,569
Selling, general and administrative	9,501	21,606	8,190	5,510	5,079	—	49,886
Depreciation, depletion, amortization and accretion	45,413	3,185	9,394	19,635	14,497	—	92,124
Impairment of long-lived assets	—	—	324	3,822	—	—	4,146
Operating income (loss)	13,202	78,074	6,349	(25,293)	(9,526)	(35)	62,771
Interest expense	1,622	241	679	1,695	73	—	4,310
Bargain purchase gain	—	—	(4,012)	—	—	—	(4,012)
Other expense	129	6	211	256	75	—	677
Income (loss) before income taxes	$ 11,451	$ 77,827	$ 9,471	$ (27,244)	$ (9,674)	$ (35)	$ 61,796
Total expenditures for property, plant and equipment	$ 85,853	$ 20,144	$ 16,376	$ 8,927	$ 2,553	$ —	$ 133,853
As of December 31, 2017:							
Goodwill	$ 86,043	$ 891	$ 2,684	$ —	$ 10,193	$ —	$ 99,811
Intangible assets, net	$ 12,392	$ 1,770	$ —	$ —	$ 1,977	$ —	$ 16,139
Total assets	$ 297,140	$ 205,275	$ 190,859	$ 88,527	$ 243,767	$ (158,325)	$ 867,243

a. Includes results for operations previously included in the well services and other energy services segments.

Year Ended December 31, 2016	Pressure Pumping	Well Services	Sand	Drilling	Other Energy Services	Eliminations	Total
Revenue from external customers	$ 123,856	$ 10,024	$ 33,835	$ 32,043	$ 30,867	$ —	$ 230,625
Intersegment revenues	569	79	4,267	—	—	(4,915)	—
Total revenue	124,425	10,103	38,102	32,043	30,867	(4,915)	230,625
Cost of revenue, exclusive of depreciation, depletion, amortization and accretion	82,552	13,540	31,895	31,848	13,186	—	173,021
Intersegment cost of revenues	4,336	26	561	(8)	—	(4,915)	—
Total cost of revenue	86,888	13,566	32,456	31,840	13,186	(4,915)	173,021
Selling, general and administrative	4,327	2,336	3,337	5,625	2,423	—	18,048
Depreciation, depletion, amortization and accretion	37,013	5,128	6,483	21,512	2,179	—	72,315
Impairment of long-lived assets	139	1,385	—	347	—	—	1,871
Operating loss	(3,942)	(12,312)	(4,174)	(27,281)	13,079	—	(34,630)
Interest expense	599	134	434	2,829	100	—	4,096
Other expense (income)	27	(566)	96	248	37	—	(158)
(Loss) income before income taxes	$ (4,568)	$ (11,880)	$ (4,704)	$ (30,358)	$ 12,942	$ —	$ (38,568)
Total expenditures for property, plant and equipment	7,673	405	528	2,709	425	—	11,740
As of December 31, 2016:							
Goodwill	$ 86,043	$ —	$ 2,684	$ —	$ —	$ —	$ 88,727
Intangible assets, net	$ 21,435	$ 132	$ —	$ —	$ —	$ —	$ 21,567
Total assets	$ 197,635	$ 128,698	$ 109,128	$ 99,868	$ 48,653	$ (81,620)	$ 502,362

Year Ended December 31, 2015	Pressure Pumping	Well Services	Sand	Drilling	Other Energy Services	Eliminations	Total
Revenue from external customers	$ 169,859	$ 28,851	$ 60,913	$ 73,032	$ 35,282	$ —	$ 367,937
Intersegment revenue	759	—	5,144	1	—	(5,904)	—
Total revenue	170,618	28,851	66,057	73,033	35,282	(5,904)	367,937
Cost of revenue, exclusive of depreciation, depletion, amortization and accretion	126,886	28,144	47,041	57,453	15,163	—	274,687
Intersegment cost of revenues	5,243	205	456	—	—	(5,904)	—
Total cost of revenue	132,129	28,349	47,497	57,453	15,163	(5,904)	274,687
Selling, general and administrative	4,901	2,286	4,264	8,573	2,376	—	22,400
Depreciation and amortization	35,729	5,697	6,305	24,627	2,141	—	74,499
Impairment of long-lived assets	1,214	88	1,905	8,917	—	—	12,124
Operating (loss) income	(3,355)	(7,569)	6,086	(26,537)	15,602	—	(15,773)
Interest income	—	—	(98)	—	—	—	(98)
Interest expense	1,822	429	225	2,928	61	—	5,465
Other expense (income)	67	687	22	1,121	372	—	2,269
Loss (income) before income taxes	$ (5,244)	$ (8,685)	$ 5,937	$ (30,586)	$ 15,169	$ —	$ (23,409)
Total expenditures for property, plant and equipment	$ 4,170	$ 6,768	$ 2,371	$ 12,651	$ 2,492	$ —	$ 28,452
As of December 31, 2015:							
Goodwill	$ 86,043	$ —	$ 2,684	$ —	$ —	$ —	$ 88,727
Intangible assets, net	$ 30,479	$ 159	$ —	$ —	$ —	$ —	$ 30,638
Total assets	$ 230,806	$ 147,268	$ 127,786	$ 123,656	$ 38,864	$ (131,968)	$ 536,412

Geographic Areas

The following table presents consolidated revenues by country based on sales destination of the products or services (in thousands):

	Year Ended December 31,		
	2017	2016	2015
United States	$ 471,745	$ 196,573	$ 331,633
Puerto Rico	203,087	—	—
Canada	16,664	34,052	36,304
Total	$ 691,496	$ 230,625	$ 367,937

The following table presents long-lived assets, excluding deferred income tax assets, by country (in thousands):

	Year Ended December 31,		
	2017	2016	2015
United States	$ 515,904	$ 389,575	$ 450,983
Puerto Rico	6,923	—	—
Canada	23,254	23,848	25,168
Total	$ 546,081	$ 413,423	$ 476,151

18. Quarterly Financial Data (unaudited)

	Three Months Ended March 31, 2017	Three Months Ended June 30, 2017	Three Months Ended September 30, 2017	Three Months Ended December 31, 2017	Total
	(in thousands, except per share data)				
Revenue from external customers	$ 30,464	$ 40,054	$ 78,389	$ 333,569	$ 482,476
Revenue from related parties	44,502	58,208	70,916	35,394	209,020
Cost of revenue, exclusive of depreciation, depletion, amortization and accretion	58,498	77,340	114,533	232,198	482,569
Selling, general and administrative expenses	6,737	7,700	8,023	27,426	49,886
Depreciation, depletion, amortization and accretion	17,237	19,893	27,224	27,770	92,124
Impairment of long-lived assets	—	—	—	4,146	4,146
Operating income (loss)	(7,506)	(6,671)	(475)	77,423	62,771
Interest expense	397	1,112	1,420	1,381	4,310
Bargain purchase gain	—	(4,012)	—	—	(4,012)
Other expense (income)	184	202	319	(28)	677
(Loss) income before income taxes	(8,087)	(3,973)	(2,214)	76,070	61,796
(Benefit) provision for income taxes	(3,106)	(2,804)	(1,413)	10,155	2,832
Net (loss) income	$ (4,981)	$ (1,169)	$ (801)	$ 65,915	$ 58,964
Net (loss) income per share (basic) (Note 11)	$ (0.13)	$ (0.03)	$ (0.02)	$ 1.48	$ 1.42
Net (loss) income per share (diluted) (Note 11)	$ (0.13)	$ (0.03)	$ (0.02)	$ 1.48	$ 1.42
Weighted average number of shares outstanding (Note 11)	37,500	39,500	44,502	44,579	41,548
Weighted average number of shares outstanding, including dilutive effect (Note 11)	37,500	39,500	44,502	44,683	41,639

	Three Months Ended March 31, 2016	Three Months Ended June 30, 2016	Three Months Ended September 30, 2016	Three Months Ended December 31, 2016	Total
	(in thousands, except per share data)				
Revenue from external customers	$ 29,518	$ 20,345	$ 20,753	$ 27,079	$ 97,695
Revenue from related parties	3,065	48,817	42,574	38,474	132,930
Cost of revenue, exclusive of depreciation, depletion, amortization and accretion	32,391	50,504	42,855	47,271	173,021
Selling, general and administrative expenses	3,614	5,206	3,195	6,033	18,048
Depreciation, depletion, amortization and accretion	17,751	18,811	17,921	17,832	72,315
Impairment of long-lived assets	—	1,871	—	—	1,871
Operating income (loss)	(21,173)	(7,230)	(644)	(5,583)	(34,630)
Interest expense	1,296	1,012	1,025	763	4,096
Other expense (income)	1	(627)	254	214	(158)
Loss before income taxes	(22,470)	(7,615)	(1,923)	(6,560)	(38,568)
Provision for income taxes	894	789	1,056	51,146	53,885
Net loss	$ (23,364)	$ (8,404)	$ (2,979)	$ (57,706)	$ (92,453)
Net loss per share (basic and diluted) (Note 11)	$ (0.78)	$ (0.28)	$ (0.10)	$ (1.61)	$ (2.94)
Weighted average number of shares outstanding (Note 11)	30,000	30,000	30,000	35,951	31,500

19. Subsequent Events

On October 19, 2017, Cobra and PREPA entered into an emergency master services agreement for repairs to PREPA's electrical grid as a result of Hurricane Maria. On January 28, 2018, Cobra and PREPA amended the initial contract to increase the total contract amount by an additional $245.4 million to a total of $445.4 million. On February 27, 2018, Cobra and PREPA again amended their contract to increase the total contract amount by an additional $500.0 million to a total of $945.4 million. In addition to continuing with its repair and restoration work, under the terms of this amendment Cobra will have the ability to source construction materials needed to rebuild the electrical infrastructure in Puerto Rico on a pass-through basis.

On February 2, 2018, the Company granted 16,022 restricted stock units with a total fair value of $0.3 million to non-employee directors. The value of the grants will be amortized over the vesting period.

Subsequent to December 31, 2017, the Company entered into an agreement to purchase sand from an unrelated third party seller with aggregate commitments of $6.8 million.

Subsequent to December 31, 2017, the Company entered into rail car, property and equipment lease agreements with aggregate commitments of $6.8 million.

Subsequent to December 31, 2017, the Company ordered additional capital equipment with aggregate commitments of $21.8 million.

Subsequent to December 31, 2017, the Company's infrastructure business entered into an air charter agreement with aggregate commitments of $1.0 million.

EXHIBIT 21.1

Mammoth Energy Services, Inc.
List of Significant Subsidiaries

Name of Subsidiary
5 Star Electric LLC
Barracuda Logistics LLC
Bison Drilling and Field Services LLC
Bison Trucking LLC
Cobra Acquisitions LLC
Cobra Energy LLC
Great White Sand Tiger Lodging Ltd.
Higher Power Electrical LLC
Mammoth Energy Partners LLC
Mammoth Energy Services Inc.
Mammoth Equipment Leasing LLC
Mr. Inspections LLC
Muskie Proppant LLC
Panther Drilling Systems LLC
Piranha Proppant LLC
Redback Coil Tubing LLC
Redback Energy Services LLC
Redback Pumpdown Services LLC
Silverback Energy Services LLC
South River Road LLC
Stingray Cementing LLC
Stingray Energy Services LLC
Stingray Logistics LLC
Stingray Pressure Pumping LLC
Sturgeon Acquisitions LLC
Taylor Frac LLC
Taylor Real Estate Investments LLC
Tiger Shark Logistics LLC
White Wing Tubular Services LLC

EXHIBIT 23.1

CONSENT OF JOHN T. BOYD COMPANY

The undersigned hereby consents to the references to our firm in the form and context in which they appear in (i) the Annual Report on Form 10-K of Mammoth Energy Services, Inc. for the fiscal year ended December 31, 2017 and (ii) the Quarterly Reports on Form 10-Q of Mammoth Energy Services, Inc. for the fiscal quarters ended March 31, 2018, June 30, 2018 and September 30, 2018. We hereby further consent to the use in such Form 10-K and Form 10-Qs of information contained in our reports setting forth the estimates of reserves of (i) Taylor Frac, LLC as of December 31, 2017, 2016 and 2015 and (ii) Piranha Proppant LLC as of December 31, 2017. We hereby further consent to the incorporation by reference in the Registration Statements on form S-8 (No. 333-217361) and Form S-3 (No. 333-221268) of Mammoth Energy Services, Inc. of such information.

Respectfully submitted,

JOHN T. BOYD COMPANY

By: /s/ Authorized Person
Name: Authorized Person
Title: Authorized Officer

February 23, 2018

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 28, 2018 with respect to the consolidated financial statements included in the Annual Report of Mammoth Energy Services, Inc. on Form 10-K for the year ended December 31, 2017. We consent to the incorporation by reference of said report in the Registration Statement of Mammoth Energy Services, Inc. on Form S-8 (File No. 333-217361).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 28, 2018

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (No. 333-217361) of Mammoth Energy Services, Inc. of our report dated August 14, 2017, relating to the financial statements of Sturgeon Acquisitions LLC, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
February 28, 2018

EXHIBIT 31.1

CERTIFICATIONS

I, Arty Straehla, Chief Executive Officer, certify that:

1. I have reviewed this Annual Report on Form 10-K of Mammoth Energy Services, Inc. (the “registrant”);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and have:
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

MAMMOTH ENERGY SERVICES, INC.

By: /s/ Arty Straehla

Arty Straehla

Chief Executive Officer

February 28, 2018

EXHIBIT 31.2

CERTIFICATIONS

I, Mark Layton, Chief Financial Officer, certify that:

1. I have reviewed this Annual Report on Form 10-K of Mammoth Energy Services, Inc. (the “registrant”);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and have:
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

MAMMOTH ENERGY SERVICES, INC.

By: /s/ Mark Layton

Mark Layton

Chief Financial Officer

February 28, 2018

EXHIBIT 32.1

**CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report on Form 10-K of Mammoth Energy Services, Inc. (the “Company”) for the annual period ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Arty Straehla, as Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”); and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

MAMMOTH ENERGY SERVICES, INC.

By: /s/ Arty Straehla

Arty Straehla
Chief Executive Officer
February 28, 2018

This certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to liability under that section. This certification shall not be deemed incorporated by reference in any filing under the Securities Act of 1933, as amended or the Exchange Act, except to the extent that the Company specifically incorporates it by reference.

EXHIBIT 32.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Mammoth Energy Services, Inc. (the "Company") for the annual period ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Mark Layton, as Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"); and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

MAMMOTH ENERGY SERVICES, INC.

By: /s/ Mark Layton

Mark Layton
Chief Financial Officer
February 28, 2018

This certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to liability under that section. This certification shall not be deemed incorporated by reference in any filing under the Securities Act of 1933, as amended or the Exchange Act, except to the extent that the Company specifically incorporates it by reference.

EXHIBIT 95.1

Mine Safety Disclosures

The following disclosures are provided pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Act”) and Item 104 of Regulation S-K, which requires certain disclosures by companies required to file periodic reports under the Securities Exchange Act of 1934, as amended, that operate mines regulated under the Federal Mine Safety and Health Act of 1977 (the “Mine Act”).

Mine Safety Information. Whenever the Federal Mine Safety and Health Administration (“MSHA”) believes a violation of the Mine Act, any health or safety standard or any regulation has occurred, it may issue a citation which describes the alleged violation and fixes a time within which the U.S. mining operator must abate the alleged violation. In some situations, such as when MSHA believes that conditions pose a hazard to miners, MSHA may issue an order removing miners from the area of the mine affected by the condition until the alleged hazards are corrected. When MSHA issues a citation or order, it generally proposes a civil penalty, or fine, as a result of the alleged violation, that the operator is ordered to pay. Citations and orders can be contested and appealed, and as part of that process, are often reduced in severity and amount, and are sometimes dismissed. The number of citations, orders and proposed assessments vary depending on the size and type (underground or surface) of the mine as well as by the MSHA inspector(s) assigned.

Mine Safety Data. The following provides additional information about references used in the table below to describe the categories of violations, orders or citations issued by MSHA under the Mine Act:

- Section 104 S&S Citations: Citations received from MSHA under section 104 of the Mine Act for violations of mandatory health or safety standards that could significantly and substantially contribute to the cause and effect of a mine safety or health hazard.
- Section 104(b) Orders: Orders issued by MSHA under section 104(b) of the Mine Act, which represents a failure to abate a citation under section 104(a) within the period of time prescribed by MSHA. This results in an order of immediate withdrawal from the area of the mine affected by the condition until MSHA determines that the violation has been abated.
- Section 104(d) Citations and Orders: Citations and orders issued by MSHA under section 104(d) of the Mine Act for unwarrantable failure to comply with mandatory health or safety standards.
- Section 110(b)(2) Violations: Flagrant violations issued by MSHA under section 110(b)(2) of the Mine Act.
- Section 107(a) Orders: Orders issued by MSHA under section 107(a) of the Mine Act for situations in which MSHA determined an “imminent danger” (as defined by MSHA) existed.

The following table details the violations, citations and orders issued to us by MSHA during the year ended December 31, 2017:

Mine (a)	Section 104 S&S Citations(#)	Section104(b) Orders (#)	Section104(d)Citations and Orders(#)	Section 110(b)(2) Violations(#)	Section107(a) Orders (#)	Proposed Assessments (2)($, amounts in dollars)	Mining Related Fatalities (#)
Taylor, WI	2	—	—	—	—	$ 289	—
Plum City, WI	1	—	—	—	—	$ 116	—
New Auburn, WI	—	—	—	—	—	$ —	—

a. The definition of mine under section 3 of the Mine Act includes the mine, as well as other items used in, or to be used in, or resulting from, the work of extracting minerals, such as land, structures, facilities, equipment, machines, tools and minerals preparation facilities. Unless otherwise indicated, any of these other items associated with a single mine have been aggregated in the totals for that mine. MSHA assigns an identification number to each mine and may or may not assign separate identification numbers to related facilities such as preparation facilities. We are providing the information in the table by mine rather than MSHA identification number because that is how we manage and operate our mining business and we believe this presentation will be more useful to investors than providing information based on MSHA identification numbers.

b. Represents the total dollar value of proposed assessments from MSHA under the Mine Act relating to any type of citation or order issued during the year ended December 31, 2017.

Pattern or Potential Pattern of Violations. During the year ended December 31, 2017, none of the mines operated by us received written notice from MSHA of (a) a pattern of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of mine health or safety hazards under section 104(e) of the Mine Act or (b) the potential to have such a pattern.

Pending Legal Actions. There were no legal actions pending before the Federal Mine Safety and Health Review Commission (the Commission) as of December 31, 2017. The Commission is an independent adjudicative agency established by the Mine Act that provides administrative trial and appellate review of legal disputes arising under the Mine Act.

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