SEITEL INC
Form 10-K
February 16, 2017
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________
Commission File Number: 001-10165

SEITEL, INC.
(Exact name of registrant as specified in its charter)

Delaware	76-0025431
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
10811 S. Westview Circle Drive, Building C, Suite 100 Houston, Texas	77043
(Address of principal executive offices)	(Zip Code)

(Registrant's telephone number, including area code) (713) 881-8900
Securities registered pursuant to Section 12(b) of the Act: None
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 ý
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 ý 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 ý
(Explanatory Note: The registrant is a voluntary filer and is therefore not subject to the filing requirements of the Securities Exchange Act of 1934. However, during the preceding 12 months, the registrant has filed all reports that it would have been required to file by Section 13 or 15(d) of the Securities Exchange Act of 1934 if the registrant was subject to the filing requirements of the Securities Exchange Act of 1934 during such timeframe.)
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 ý No ¨

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

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

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

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

The equity interests in the registrant are not held publicly. On February 13, 2017, there were a total of 100 shares of common stock, par value $0.001 per share, outstanding.

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K (this "Annual Report") contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Statements contained in this report about our future outlook, prospects, strategies and plans, and about industry conditions, demand for seismic services and the future economic life of our seismic data are forward-looking, among others. All statements that express belief, expectation, estimates or intentions, as well as those that are not statements of historical fact, are forward-looking. The words "believe," "expect," "anticipate," "estimate," "project," "propose," "plan," "target," "foresee," "should," "intend," "may," "will," "would, and similar expressions are intended to identify forward-looking statements. Forward-looking statements represent our present belief and are based on our current expectations and assumptions with respect to future events and their potential effect on us. While we believe our expectations and assumptions are reasonable, they involve risks and uncertainties beyond our control that could cause the actual results or outcome to differ materially from the expected results or outcome reflected in our forward-looking statements. In light of these risks, uncertainties and assumptions, the forward-looking events discussed in this Annual Report may not occur. Such risks and uncertainties include, without limitation, actual customer demand for our seismic data and related services, the timing and extent of changes in commodity prices for natural gas, crude oil and condensate and natural gas liquids, conditions in the capital markets during the periods covered by the forward-looking statements, the effect of economic conditions, our ability to obtain financing on satisfactory terms if internally generated cash flows are insufficient to fund our capital needs, the impact on our financial condition as a result of our debt and our debt service, our ability to obtain and maintain normal terms with our vendors and service providers, our ability to maintain contracts that are critical to our operations, changes in the oil and gas industry or the economy generally and changes in the capital expenditure budgets of our customers.

Also note that we provide a cautionary discussion of risks and uncertainties under the captions "Item 1A. Risk Factors," "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Annual Report.

The forward-looking statements contained in this report speak only as of the date hereof and readers are cautioned not to place undue reliance on such forward-looking statements. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason. All forward-looking statements attributable to Seitel, Inc. or any person acting on its behalf are expressly qualified in their entirety by the cautionary statements contained or referred to herein, in this Annual Report and in our future periodic reports and registration statements filed with the Securities and Exchange Commission ("SEC").

PART I

Item 1. Business

General

We are a leading provider of onshore seismic data to the oil and gas industry in North America. We own an extensive library of onshore and offshore geological data that we have accumulated since our inception in 1982. We believe our data library is one of the largest onshore three-dimensional ("3D") databases available for licensing in North America and includes leading positions in oil, liquids-rich and natural gas unconventional plays as well as conventional areas. As of February 2017, we own approximately 44,300 square miles of onshore 3D data, consisting of 30,350 square miles in the United States (69%) and 13,950 square miles in Canada (31%). We have a leading market position in key geographies in the North American unconventional onshore oil and gas plays where exploration and production ("E&P") companies have been focusing their efforts in recent years. Approximately 55% of our onshore 3D library is comprised of data located in unconventional plays. In 2015, we began to expand our data library coverage into Mexico through the reprocessing of existing two-dimensional ("2D") data which can be licensed to E&P companies.

Our business model is to acquire data selectively in geological formations that we believe will support drilling from a variety of oil and gas producers over an extended period of time. We design and manage new surveys and license them to initial clients which typically fund a significant portion (55% to 75%) of the total cost of each survey (referred to as “client underwriting”). Seitel typically owns 100% of the acquired data and licenses the data to additional parties on a non-exclusive basis (referred to as “resales”). Such resales are unlimited in both time and amount and require minimal incremental cash costs. Since embarking on our investment in unconventional data in 2008, we have achieved, on a historical basis, a payback period on these investments of about three to four years on average despite some slowdown in returns in the recent industry downturn. Our long-lived, diverse data library built over three decades continues to provide value to our customers, with 59% of our 2016 3D onshore resale revenue coming from data over five years old.

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We believe that we have low fixed costs and a highly flexible operating model, as we do not own any seismic survey equipment or directly employ field personnel. Instead, we outsource those functions by contracting with third-party specialists, as required, in various facets of the data acquisition process in order to complete surveys to expand our data library. We also use sales commissions to create incentives for our sales force while matching our costs to our achieved sales. We believe this business model provides enhanced flexibility, allowing us to optimize our level of investment for the market environment and resulting in substantially lower cash flow volatility by enabling us to respond quickly to changes in demand and shifts in client geographic focus.

We serve a market which includes over 1,500 companies in the oil and gas industry. Our customers include large independent and major integrated oil and gas companies as well as small and mid-cap E&P companies. The importance of geological data in the exploration and development process drives demand for data in our library. Specifically, our customers use seismic data to identify geographical areas where subsurface conditions are favorable for oil and gas exploration and to optimize development and production of oil and gas reserves. Seismic data provides valuable insight for operators including a target zone's thickness, as well as faulting pattern complexity, helping with the design of horizontal drilling programs and minimizing the potential for uneconomic wells.

To support our seismic data licensing business and our clients, we maintain warehouse and electronic storage facilities at our Houston, Texas headquarters and our Calgary, Alberta locations. Through our Seitel Solutions business unit (“Solutions”), we offer the ability to access and interact with the seismic data we own and market via a standard web browser and the Internet.

From 2014 through 2016, approximately 98% of our revenues were generated from customers underwriting data acquisitions and revenue from licensing of seismic data. Other revenues during these years were primarily derived from Solutions for reproduction and delivery of seismic data licensed by our clients. See Note L to Consolidated Financial Statements for information about our revenue by geographical area.

We are a private company controlled by ValueAct Capital Master Fund, L.P. (“ValueAct”) and funds managed by affiliates of Centerbridge Partners, L.P. (“Centerbridge”). We are incorporated under the laws of the State of Delaware. Our principal executive offices are in Houston, Texas.

Description of Operations

Seismic Data

E&P companies consider seismic data an important tool in finding and exploiting hydrocarbons. E&P companies use seismic data in oil and gas exploration and development efforts to increase the probability of drilling success, to better delineate existing oil and gas fields and to augment their reservoir completion and management techniques. In unconventional plays, E&P companies use seismic data as a development tool to better identify efficient drilling plans and maximize production by identifying and understanding a series of critical characteristics of the targeted resource. The cost of seismic data represents a small portion of the total cost of most projects, but provides substantial benefits to operators. 3D seismic data provides a graphic depiction of the earth’s subsurface from two horizontal dimensions and one vertical dimension, rendering a more detailed picture than 2D data, which presents a cross-sectional view from one vertical and one horizontal dimension. The more comprehensive geophysical information provided by 3D surveys significantly enhances an interpreter’s ability to evaluate the probability of the existence and location of oil and gas deposits as well as the target zone’s thickness and faulting pattern complexity. However, the cost to create 3D seismic data is significantly more than the cost to create 2D seismic data. As a result, 2D data continues to be used by clients for preliminary, broad-scale exploration evaluation, as well as in determining the location and design of 3D surveys. 3D surveys can then be used for more detailed analysis to maximize actual drilling potential and success.

Although we amortize our seismic data library investment over a maximum period of four years, much of our seismic data has continued to generate licensing revenue past the amortization period. Assuming the data is sampled and gathered adequately in the field recording phase, it is amenable to re-evaluation and re-presentation multiple times, using new or alternate processing techniques or updated knowledge of the Earth model.

Management believes the level of resales from various vintages of our seismic data is useful in assessing the resiliency and value of our seismic data library. Management considers estimated longevity of and foreseeable demand for data in determining

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whether to undertake new data acquisition projects. For the year ended December 31, 2016, resale revenue from 3D onshore data was recognized from net historical investments made in the indicated periods (in thousands):

	Resale Revenue	Percentage	Net Investment [1]	Percentage
Investments prior to 2012	$39,305	59 %	$ 586,658	72 %
Investments 2012 through 2016	27,722	41 %	225,544	28 %
Total 3D onshore	$67,027	100 %	$ 812,202	100 %

(1) Net investment, a non-GAAP measure, reflects total data cost less client underwriting before fair value adjustments resulting from the 2007 merger between Seitel Acquisition Corp. with and into Seitel, Inc. (the "Merger"). The GAAP measure to which historical net investment is most directly comparable is net book value. We believe that the presentation of historical net investment is important as it reflects our capital investment in our seismic data library net of the portion underwritten by our customers. For a reconciliation of historical net investment to net book value, see "Reconciliation of Historical Net Investment to Net Book Value" below.

The following presents a reconciliation of resale revenue for 3D onshore data to total revenue for the year ended December 31, 2016 (in thousands):

Total resale revenue – 3D onshore	$67,027
Other revenue components:	
Other resale revenue (principally 2D and offshore)	3,969
Acquisition underwriting revenue	21,458
Solutions and other revenue	2,092
Total revenue	$94,546

Reconciliation of Historical Net Investment to Net Book Value

The following presents a reconciliation of historical net investment for 3D onshore data (a non-GAAP financial measure) to net book value of our seismic data library at December 31, 2016 (the most directly comparable GAAP financial measure) (in thousands):

Historical net investment in seismic data – 3D onshore	$812,202
Add:	
Acquisition underwriting revenue – 3D onshore	942,438
Other seismic data investment (principally 2D and offshore)	385,154
Foreign currency translation	24,058
Seismic projects in progress	14,328
Fair value adjustment resulting from the Merger	275,235
Less:	
Historical impairment charges	(112,923)
Accumulated amortization (including historical amounts pre-Merger)	(2,224,570)
Net book value	$115,922

Data Library Overview

We believe our data library is one of the largest onshore 3D databases available for licensing in North America. We have built our onshore 3D library over more than 20 years with approximately $1.8 billion in gross investments and we view our library as an asset that would be time- and cost-prohibitive for others to replicate. Approximately 55% of our onshore 3D library is comprised of data located in unconventional plays. We believe we are well positioned due to the geographic diversity of our data library, including data in oil-focused and liquids-rich plays such as the Eagle Ford/Woodbine, Permian Basin, Niobrara/Bakken, Utica/Marcellus, Anadarko Basin, Montney and Duvernay and in natural gas-focused plays such as the Haynesville, Louisiana Cotton Valley and Horn River, with over 24,000 miles of data in unconventional areas.

Our library also consists of data targeted at conventional plays in both the U.S. and Canada. We also own a library of 3D offshore data covering parts of the shelf and certain deep water areas in the Western and Central U.S. Gulf of Mexico. In addition, we own or manage approximately 1.1 million linear miles of 2D data concentrated primarily in North America, both onshore and offshore.

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In 2015, we began to expand our data library coverage into Mexico. We are reprocessing existing onshore 2D data owned by the Mexican government and have the rights to license the reprocessed data to E&P companies.

The following table describes our 3D seismic data library as of February 13, 2017:

	Completed Surveys			Surveys in Progress
3D Data Library	Square Miles [1]	Percentage of Subtotal		Square Miles [1]
Eagle Ford/Woodbine	7,500	25	%	50
Niobrara/Bakken	2,750	9	%	—
Utica/Marcellus	1,500	5	%	—
Haynesville	1,200	4	%	—
Permian	1,100 [2]	4	%	—
Anadarko Basin	800	3	%	—
Louisiana Cotton Valley	500	2	%	150
Conventional 3D	15,000	48	%	—
Total U.S. Onshore	30,350	100	%	200
Duvernay	4,000	29	%	—
Montney	3,950	28	%	50
Horn River	1,050	8	%	—
Conventional 3D	4,950	35	%	—
Total Canada	13,950	100	%	50
Total 3D Onshore	44,300	81	%	250
U.S. Offshore	10,500	19	%	—
Worldwide Total	54,800	100	%	250

(1)Square miles reflect mileage net to our revenue interest.
(2)We also broker approximately 3,200 square miles of data in the Permian on behalf of certain E&P companies.

Our data library is a highly valuable asset that has historically generated strong returns on capital. The technical and informational usefulness of our data has generally not declined over time. Demand for data is driven by the level and location of customer exploration and development activity and not the age of the data. Because of our positioning in favorable geographies and the long life of the data, we believe there is significant built-in potential for repeat licensing of data at little or no marginal cost. The existing library is highly defensible as the customer's cost of licensing data is typically much lower than the cost of creating a new survey. We believe there is little incentive for competitors to survey areas where we already have data.

Onshore U.S. and Canada: Since 2008, our capital investment in both the U.S. and Canada has been focused on unconventional plays, initially in the shale gas areas and, since 2011, shifting towards oil-focused and liquids-rich objectives. These changes in focus are made in accordance with the activity of our clients and our ability to shift with them is an important component of our growth strategy.

The U.S. onshore 3D conventional sector of our seismic data library is mainly comprised of our Gulf Coast Texas and southern Louisiana/Mississippi components, which we began accumulating in 1993. We also have relatively small amounts of 3D seismic data in other areas, such as Alabama, California, Michigan and Northern Louisiana as well as an extensive 2D data library that continues to contribute to our licensing sales.

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The Canadian onshore 3D conventional sector of our seismic data library is mainly comprised of data within the Western Canadian Basin, which we began accumulating in 1998. We also have an extensive 2D data library that continues to contribute to our licensing sales.

Offshore U.S. Gulf of Mexico: Our library of offshore data covers parts of the U.S. Gulf of Mexico shelf and certain deep water areas in the Western and Central U.S. Gulf of Mexico. We have accumulated our U.S. Gulf of Mexico offshore 3D data since 1993.

Mexico: We are reprocessing existing onshore 2D data owned by the Mexican government and have the rights to license the reprocessed data to E&P companies. As of February 13, 2017, we have been granted approvals for and have already begun licensing three areas totaling approximately 8,300 linear miles.

Data Library Growth

We regularly add to our library of seismic data by: (1) recording new data, (2) buying ownership of existing data for cash, (3) obtaining ownership of existing data through non-monetary exchanges and (4) creating new value-added products from data existing within our library.

Underwritten Data Acquisitions: We design and manage new seismic surveys that are specifically suited to the geology and environmental conditions of the area using the most appropriate technology available. Typically, one or more customers will underwrite or fund a significant portion of the direct cost in exchange for a license or licenses to use the resulting data. Under the terms of these licenses, the customers may occasionally have a limited exclusivity period. We consider the contracts executed up to the time we make a firm commitment to create the new seismic survey as underwriting or pre-funding. Any subsequent licensing of the data while the survey is in progress or once it is completed is considered a resale license. Almost all of our new data acquisition activity during 2016 occurred in the U.S., with a focus in the Louisiana Cotton Valley and the Permian. All field work on these projects is outsourced to subcontractors. A significant percentage of the data processing for our U.S. and Canadian projects is processed by our internal data processing group located in Houston. We employ experienced geoscientists who design seismic programs and oversee field acquisition and data processing to ensure the quality and longevity of the data created.

Cash Purchases: We purchase data for cash from oil and gas companies, other seismic companies or financial investors in seismic data when opportunities arise and that meet our investment criteria.

Non-Monetary Exchanges: We grant our customers a non-exclusive license to selected data from our library, provide reproduction services or provide data processing services (or some combination of those items) in exchange for ownership of seismic data from the customer. The data that we receive is distinct from the data that is licensed to our customer. These transactions will tend to be for individual surveys or groups of surveys, rather than whole libraries. Occasionally, we also use non-monetary exchanges in conjunction with data acquisitions and cash purchases. In addition, we may receive advanced data processing services on certain existing data in exchange for a nonexclusive license to selected data from our library.

Value-Added Products: We create new products from existing seismic surveys in our library by extracting a variety of additional information from these surveys that was not readily apparent in the initial products. Opportunities to extract such additional information and create such additional products may result from information from secondary sources, alternative conclusions regarding the initial products and applying alternate or more complex processes to the initial products, or some combination of these factors. Additional products may include 5D Interpolation, Pre-Stack Depth Migration volumes, Amplitude Versus Offset volumes, Complex Attribute volumes and Rock Property volumes. The cost of these products may be underwritten by one or more customers in exchange for a license or licenses to use the resulting data or we may determine to fund the cost of certain of these products based on anticipated demand by our clients. These data products are licensed to the industry on a non-exclusive basis. Work on these projects may be performed by our internal data processing groups, outsourced to specific specialists in the arena or conducted under an alliance with a particular specialist. We employ experienced geoscientists who design these value-added products and oversee the processing to ensure the quality and longevity of the data created.

Competitive Strengths

We believe we have the following competitive strengths:

Large and Diverse Data Library with Leading Market Position in Key Oil and Gas Producing Regions: We believe we have one of the largest onshore 3D seismic data libraries available for licensing in North America. Our data covers a diverse range of oil and gas producing regions in the United States and Canada and we believe it provides us with leading positions in oil, liquids-rich and natural gas unconventional plays as well as conventional areas. As of February 2017, we have over 24,000

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square miles of unconventional 3D data. As industry activity dictates, we will focus on further development of existing plays where our clients are active. Our competitive advantage is driven by our ability to:

- successfully bid for new seismic surveys that are in our areas of focus as a result of our knowledge of data return characteristics for similar data in our existing library;
- creatively market our data library with an innovative strategy, which includes tailoring licenses to meet our clients' needs;
- generate client trust by delivering surveys on time that meet oil and gas client requirements particularly those clients that are early participants; and
- retain and grow valuable client relationships.

With one of the largest onshore seismic data libraries in the active North American oil and natural gas basins, we have an established competitive position. Since 1994, we have invested approximately $2.1 billion to build our data library, with a gross investment of approximately $1.8 billion, $0.8 billion net of underwriting, in onshore 3D data. We believe that the current replacement cost of our seismic library significantly exceeds our original investment, and that our broad geographic coverage and strong presence in the active North American onshore oil and gas basins coupled with our domain expertise creates significant barriers to replication and a defensible market position. We believe competitors will generally not shoot over areas already in our library because it is not economically viable to do so.
Multiple Revenue Opportunities Lead to Strong Returns on New and Existing Data: We derive revenue from the non-exclusive licensing of our data. Importantly, data within our library can be licensed on a non-exclusive basis multiple times over a span of many years with minimal incremental costs, if any. Several factors lead to multiple licensing of our data which drives high returns on our investments over time. An area captured by a 3D survey may have multiple mineral holders within a particular stratigraphic layer as well as vertically across layers. Also, new oil and gas field discoveries, new drilling technologies and pipeline and oil and gas infrastructure expansion can cause renewed activity in a previously assessed surrounding area. Due to the capital intensive nature of developing unconventional plays, many oil and gas companies seek partners to share in the cost of development and these partners will often need to purchase licenses for their own use. In addition, merger and acquisition activity often requires re-licensing of data following a change in field ownership. Moreover, prospective developers and investors without mineral rights may seek our data.
We have proven our ability to license onshore data for extended periods after its creation. For the year ended December 31, 2016, 59% of total resale revenue for 3D onshore data came from data acquired before 2012.
Ability to Adjust Quickly to Oil and Gas Industry Cycles: Our variable operating structure allows us to curtail overhead costs quickly during cyclical downturns in the oil and gas industry because we have no fixed overhead costs related to maintaining seismic equipment or crews and our employee compensation structure is commission-based and bonus-centric. As distinct from our business model, the majority of seismic companies own and operate seismic equipment and crews, creating fixed operating expenses and less flexible cost structures. In addition, most of our capital expenditures are discretionary additions to our seismic data library with significant underwriting commitments from customers, allowing us to reduce capital expenditures when necessary.
We operate with a low cost structure by maintaining an efficient base of assets and employees. We do not own seismic acquisition equipment or employ seismic acquisition crews, but engage, as required, third-party contractors with qualified equipment to shoot new data. We believe this, in addition to the majority of our capital expenditures being discretionary, minimizes our ongoing capital requirements and results in substantially less volatility in cash flows by enabling us to respond quickly to changes in demand. In addition, the creation of new surveys provides cost-effective growth opportunities because we impose strict capital investment thresholds with targeted underwriting levels averaging 60% to 70% and typically do not start work on new acquisition programs without an underwriting commitment. Additionally, we may seek higher levels of underwriting in order to minimize our cash investment while still adding new data to our library. In 2016, underwriting revenue exceeded new seismic acquisition costs, resulting in an overall underwriting level of 113%. Average underwriting levels in 2015 and 2014 were 63% and 69%,

respectively.

Seismic Data Has an Attractive Value Proposition Among Our Blue Chip Customer Base: Our data is key to oil and gas exploration and development activity. Understanding geological structure maximizes production and returns on client investments; however, seismic data purchases represent a small fraction of total drilling and completion costs. We serve a market that includes over 1,500 companies in the oil and gas industry. Our customer base ranges from some of the largest independent oil companies in the world to small, single-basin E&P companies and also includes global oil and gas companies, typically with very little customer concentration.

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We believe that the quality of our data, the breadth of its coverage in the major active onshore basins in North America and our longstanding commitment to client service enables us to attract top-tier clients and maintain and grow existing client relationships. These relationships also create access to additional data surveys and sales opportunities.

Experienced Management Team: Our executive management team is comprised of individuals with an average of over 25 years of relevant experience. Robert Monson, our CEO and President, has more than 30 years of industry experience, while Marcia Kendrick, our CFO, joined us in 1993 and has over 25 years of industry experience. Richard Kelvin, our CTO and President of Seitel Canada Ltd. and Randy Sides, our President of Seitel Data, Ltd., both also have over 25 years of industry experience. Our expertise is in the selection, design and management of seismic surveys. We also believe we maintain the largest sales and marketing group in the industry.

Corporate Strategy

Underwritten Data Acquisitions: We add data to our library primarily by contracting with third-party specialist service providers to create new subsurface geological data, which we design and own. Typically, one or more customers will underwrite or fund a significant portion of the direct cost of a seismic survey in exchange for a license or licenses to use the resulting data. The relatively high level of underwritten acquisition costs, typically 55% to 75% of the cost of the survey, lowers our initial capital requirements and enhances our return on investment. We maintain a disciplined return on investment approach to capital expenditures. We only intend to pursue new acquisition projects if we believe that conditions exist for repeated licensing of the same data over an extended period of time. We typically seek significant underwriting commitments before undertaking new acquisition projects as underwriting levels are generally a predictor of long-term demand for seismic data. We target an average of 60% to 70% underwriting level for all new seismic acquisition projects on an aggregate basis and may target higher underwriting levels in periods of industry downturn. We achieved 113% average underwriting levels for 2016 and achieved 63% and 69% average underwriting for new seismic acquisition projects in 2015 and 2014, respectively. Additionally, when acquiring 3D surveys, we consider the proximity to 3D surveys already in the library. We believe that there is greater value in contiguous data, or reasonably close concentrations of surveys in a single area. We typically own 100% of the acquired data and license the data to additional parties on a non-exclusive basis. Such resales are unlimited in both time and amount and require no to minimal incremental cash costs. Our long-lived, diverse data library built over three decades continues to provide value to our customers, with 59% of our 2016 3D onshore resale revenue coming from data over five years old.

Provide Value to Customers through Deep Industry Knowledge and Technical Expertise: As a provider of multi-client data services, we deliver value to our clients through several aspects of our business. Our extensive expertise and local intelligence in designing and managing surveys is not generally available to our client base. We also create value-added products from the data in our library, primarily by applying complex imaging technology, such as complex depth imaging. These value-added products enhance the useful information that can be extracted from a given data set. As a large onshore data library owner, we have an existing data “footprint,” often providing further cost efficiencies and higher-quality data for new surveys. Clients are disposed to underwrite our surveys as the cost to license multi-client data is significantly less than the cost to commission a proprietary survey. Finally, our clients maintain anonymity both within the local community and amongst competitors through contracting with Seitel.

Expand Library in a Disciplined and Cost-effective Manner: The substantial majority of our library additions come from new seismic data creation. We also grow our data library through cash purchases of existing seismic data, non-monetary data exchanges and new value-added products created from existing data. We focus our data acquisition efforts on oil and natural gas producing areas that we believe are well suited to benefit from current and emerging trends in the E&P industry. The decision to make capital investments is weighed against the estimated length of the payback period and projected return on capital. We believe ample opportunities exist to grow our library in existing plays and, as oil and gas industry activity dictates, to expand into emerging areas. We use proprietary information tools and apply our management expertise to select among our pipeline of new survey opportunities. We typically pursue a new acquisition project only if it has a significant underwriting commitment from our customers and if we believe that conditions exist for repeated licensing of the data over an extended period of time. We are thorough in our evaluation of survey opportunities and are selective in adding prospective surveys to our pipeline and therefore not all surveys will meet our return requirements.

Leverage Internal Geophysical and Operations Management Expertise while Outsourcing Lower Margin Services: Our strong geophysical, technical and field operating management expertise is essential in maintaining our leadership through our ability to design surveys with attractive return potential and to manage their creation. We will continue to outsource the non-core, fixed-cost intensive services, including surveying, permitting and data capture involving field equipment and crews. This strategy enables us to select vendors that we believe offer the best price, equipment and skill sets for a particular environment, geographical location or geophysical objective and provides us with access to state-of-the-art equipment and emerging

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technologies. We believe this operating model also gives us the flexibility to control costs to respond appropriately to changing market conditions.

Maintain a Strong Balance Sheet and Ample Liquidity: We believe a strong balance sheet and ample liquidity are critical elements to managing the business through industry cycles. We intend to fund data acquisitions with the cash flow generated from operations.

Industry Overview

Overview of Seismic Data: E&P companies consider seismic data an important tool in finding and exploiting hydrocarbons. E&P companies use seismic data in oil and gas exploration and development efforts to increase the probability of drilling success, to better delineate existing oil and gas fields and to augment their reservoir completion and management techniques. Historically, seismic data was tied to exploration capital expenditures, which are significantly more volatile, as E&P companies used seismic data to increase the success rate of discovering hydrocarbon deposits. With the shift to unconventional plays, E&P companies use seismic data in those plays as a development tool to better identify efficient drilling plans and maximize production by identifying and understanding a series of critical characteristics of the targeted resource. The cost of seismic data represents a small portion of the total cost of drilling and completion for most projects, but provides substantial benefits to operators, including minimizing potential for uneconomic wells.

Drivers of Ongoing Demand for Seismic Data: There are many drivers that cause seismic data to be licensed repeatedly by different customers over a long time period, including fractured mineral positions, stratified mineral interests, partnerships, lease and option turnover, correlation to well analogs, commodity pricing, improvements in data processing techniques and developments in drilling and production technology.

Increased merger and acquisition activity, including joint ventures, may also generate increased licensing fees for seismic data providers. Licenses to seismic data are generally structured such that they do not transfer in the case of a change of control and they are not accessible to partners. Both circumstances require additional payments for new licenses.

North American Oil and Gas Markets: The emergence of shale and other unconventional plays has led to significant increases in production of oil and natural gas in North America. Beginning in the fourth quarter of 2014 and continuing throughout 2015 and into early 2016, oil prices declined significantly because of continued high production and high global inventories. As a result of these price declines, E&P companies reduced their capital expenditure budgets in 2015 and further in 2016 in an effort to protect cash flows, resulting in reduced drilling. U.S. E&P operators cut cost structures, generated drilling efficiencies and obtained service cost concessions to lower their cost of drilling. In the fourth quarter of 2016, OPEC and non-OPEC producers agreed to cut oil production beginning in early 2017 which led to rising and stabilizing oil prices. This improvement in oil prices has resulted in increased rig counts and seems to indicate the bottom of the cycle has been reached. Current E&P spending surveys indicate capital spending in North America by E&P companies is expected to increase approximately 30% to 45% in 2017.

The Energy Information Administration (“EIA”) expects U.S. crude oil production to increase in 2017 after experiencing declines in 2016. Based on the EIA’s Short-Term Energy Outlook dated January 10, 2017, the EIA expects U.S crude oil production to average 9.0 million barrels per day in 2017 and 9.3 million barrels per day in 2018 compared to 8.9 million barrels per day in 2016. Global consumption is expected to grow by 1.6 million barrels per day in 2017 and 1.5 million barrels per day in 2018. In its January 2017 report, the EIA predicts the price of West Texas Intermediate crude oil to average $52.50 per barrel in 2017 and $55.18 per barrel in 2018, as compared to the average of $43.33 in 2016.

In this same report, the EIA projects that total U.S. natural gas production will average 73.8 billion cubic feet per day (Bcf/d) in 2017 and 76.6 Bcf/d in 2018 compared to 72.4 Bcf/d in 2016. U.S. natural gas consumption is expected to grow slightly, averaging 75.4 Bcf/d in 2017 and 76.9 Bcf/d in 2018 compared to 75.1 Bcf/d in 2016. The EIA expects natural gas working inventories to be 3% to 5% below its most recent 5-year average. The EIA predicts that natural gas spot prices will show significant improvement in 2017 and 2018, with an average of $3.55 per million British thermal units (MMBtu) in 2017 and $3.73 per MMBtu in 2018 as compared to the average of $2.51 per MMBtu in

2016.

We are anticipating 2017 to be the first year of recovery in upstream capital spending due to improved commodity prices. However, uncertainty remains as to the effectiveness and duration of the concurrent OPEC and non-OPEC production cuts, which could influence oil prices in either direction. Also, the potential for efficiency gains and cost reductions from non-OPEC producers in the higher price environment could result in additional volumes of supply that could put downward pressure on oil prices. We remain cautiously optimistic that we will see improvements in seismic spending from our E&P clients in 2017.

Importance of Seismic Data: We believe the use of 3D seismic data will continue to be an important part of oil and gas companies’ exploration and development projects as they are continually looking to reduce drilling risk, decrease oil and natural gas finding costs and increase the efficiencies of reservoir location, delineation, completion and management. In addition, we believe that seismic data is a key component of oil and gas production activity in the unconventional plays. Seismic data can provide a wealth of insight into the targeted resource, including areal extent, depth, thickness, faulting patterns and a number of complex rock properties. Such insights enhance our customers’ ability to design efficient and productive horizontal drilling and fracking programs. Understanding these unique features is critical for our customers as they develop their horizontal drilling plans, which can result in lateral drilling that reaches over one mile in each direction.

Licenses and Marketing

We actively market data from our library to customers under non-exclusive license agreements using a well-developed marketing strategy combined with strong geophysical expertise. Our licenses are generally non-assignable and typically provide that in the event of a change of control of a customer-licensee, the surviving entity must pay a fee to maintain a license for any data it seeks to continue to use and for which such entity previously did not have a license. We employ an experienced sales force and it is our operating philosophy to actively market our seismic library. Our team of dedicated marketing specialists seeks to maximize license sale opportunities and create innovative methods of contracting opportunities by monitoring petroleum industry exploration and development activities through close interaction with E&P companies on a daily basis.

Licenses generally are granted for cash, payable within 30 days of invoice, although we occasionally permit a customer to make an initial payment upon inception of the license followed by periodic payments over time, usually not more than 12 months. Some licenses provide for additional payments to us if the licensee acquires additional mineral leases, drills wells or achieves oil or gas production in the areas covered by the licensed data.

Fundamental to our business model is the concept that once seismic data is created it is owned by us and added to our library for licensing to customers in the oil and gas industry on a non-exclusive basis. Since the data is a long-lived asset, such data can be licensed repeatedly and over an extended period of time to different customers at the same time.

Backlog

At February 13, 2017, we had gross capital expenditure commitments related to data creation projects of approximately $17.4 million. We anticipate that the majority of this backlog will be recognized over the next 12 months. This is compared to gross capital expenditure commitments at February 16, 2016 of $16.5 million.

Seitel Solutions

To support our seismic data licensing business and our clients, we maintain warehouse and electronic storage facilities at our Houston, Texas headquarters and our Calgary, Alberta locations. Through our Solutions business unit, we offer the ability to access and interact with the seismic data we own and market via a standard web browser and the Internet. Using proprietary technology, we store, manage, access and deliver data, tapes and graphic cross-sections to our licensees. In addition, Solutions offers use of its proprietary quality control software to the seismic brokerage community principally in Calgary, Alberta, Canada. We also offer data management services to select clients.

Customers

We market our seismic data to a varied customer base. Our customers include independent oil and gas companies, major integrated oil and gas companies and national oil companies, as well as small and mid-cap E&P companies and private prospect generating individuals. One customer accounted for more than 10% of our total revenue during the year ended December 31, 2016, totaling approximately $15.4 million (16.3%). During the year ended December 31, 2015, two customers accounted for more than 10% of our revenue, totaling approximately $14.5 million (14.5%) and $12.5 million (12.5%) of our revenues each. One customer accounted for approximately $25.7 million (13.0%) of our revenue during the year ended December 31, 2014. We believe that the quality of our data, the breadth of its coverage in the major active North American basins and our longstanding commitment to client service enables us to attract top-tier clients. Because we do not acquire data speculatively, strategic relationships with our customers have been

and will continue to be critical to our growth. We do not believe that the loss of any single customer would have a material adverse impact on our business, cash flows or results of operations.
Competition
The creation and licensing of seismic data is competitive. Customers consider several factors, including location of data, price, technological expertise and reputation for quality and dependability, when choosing a service provider. There are a number of geophysical companies that create, market and license seismic data and maintain seismic data libraries. Rather than outsourcing

their seismic data activities, some oil and gas companies create their own seismic data libraries, which they license to others. Our largest competitors, many of whom are engaged in acquiring seismic data, as well as maintaining a data library, are CGG; Geokinetics, Inc.; Geophysical Pursuit, Inc.; FairfieldNodal; Pulse Seismic Inc.; Seismic Exchange, Inc.; TGS Nopec; Vector Seismic Data Processing, Inc., a subsidiary of Schlumberger Limited,; and WesternGeco. Many of our competitors have substantially larger revenues and resources than we do.

Regulations

Our business operations and the demand for our products and services are subject to a variety of federal, provincial, state, foreign and local laws and regulations in the United States, Canada and Mexico, including requirements relating to environmental protection and worker health and safety laws. These regulations impose numerous obligations applicable to our operations including permitting before commencing regulated activities and the limitation or prohibition of seismic activities in environmentally sensitive or protected areas. Further, these laws, regulations and government policies may change as a result of political, economic or social climate. Stringent new and future laws, regulations and policies concerning hydraulic fracturing, greenhouse gas emissions and the use of renewable energy sources could negatively impact the operations of our customers. The Environmental Protection Agency (EPA) for example issued regulations in 2012 and 2015 which govern performance standards for the oil and natural gas industry and in 2014 issued a notice of proposed rulemaking regarding the reporting of the chemical substances and mixtures used in hydraulic fracturing. The federal Bureau of Land Management (BLM) published a final rule in March 2015 which establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian lands. An injunction was issued in September, however, by the U.S. District Court of Wyoming, which bars implementation of this rule. On October 9, 2015, the U.S. Court of Appeals for the Sixth Circuit stayed the Clean Water Rule nationwide pending further action of the court. The court acknowledged that clarification of the Clean Water Act is needed and that “agencies conscientiously endeavored, within their technical expertise and experience, and based on reliable peer-reviewed science, to promulgate new standards to protect water quality that conform to the Supreme Court’s guidance.”

In response to this decision, the EPA and the Department of Army resumed nationwide use of the agencies’ prior regulations defining the term “waters of the United States.” Those regulations will be implemented as they were prior to August 27, 2015, by applying relevant case law, applicable policy, and the best science and technical data on a case-by-case basis in determining which waters are protected by the Clean Water Act. In another example, several legal initiatives and regulations have emerged seeking to reduce greenhouse gas emissions which the EPA has found to present a danger to public health and the environment. This includes regulations under existing provisions of the federal Clean Air Act that restrict emissions of greenhouse gases and require annual monitoring and reporting of greenhouse gas emissions from certain production sources in the United States. The adoption of these types of regulations, legislation or other regulatory initiatives and restrictions on hydraulic fracturing activities and greenhouse gas emissions could burden operators and adversely affect the production of crude oil and natural gas, which would, in turn, adversely affect our revenues and results of operations by decreasing demand for our seismic data and related services. For more information on hydraulic fracturing, see “Item 1A. Risk Factors” beginning on page 14. We invest financial and managerial resources to comply with these laws, regulations and related permit requirements. Various governmental authorities have the power to enforce compliance and penalize non-compliance with these laws and regulations as well as the permits issued under them. The inability to timely obtain required permits may result in delays in acquiring new data for our data library or may cause operating losses. As laws and regulations and our business change over time, the future cost of compliance is uncertain and could be material. Regulations which limit exploration or production activities by oil and gas companies could adversely affect us by reducing the demand for our seismic data. For example, in response to increased public concerns that hydraulic fracturing may adversely affect drinking water supplies, increase emissions of perceived greenhouse gases and/or adversely affect local community infrastructure, including, for example, through increased truck traffic, hydraulic fracturing has become the subject of controversy and increased opposition by certain environmental groups. It has been the subject of numerous private and governmental studies, and has triggered increased governmental regulation. While the process is typically regulated by state oil and gas commissions, several federal agencies including the EPA and BLM, have asserted regulatory authority over certain aspects of the process. Congress has from time to time considered the adoption of legislation to provide for federal regulation of hydraulic fracturing and regional or state agencies with control over the withdrawal of water used in hydraulic fracturing activities may impose stringent conditions on, or delay or prohibit, such water withdrawals. At the state level, a growing number of states have adopted legal requirements that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing activities. In addition, local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Furthermore, several federal governmental agencies including the EPA are working with states and other key stakeholders to assess adverse impacts that hydraulic fracturing may have on drinking water or groundwater sources or otherwise to help ensure that natural gas extraction does not come at the expense of public health and the environment. The EPA's final report, "Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States," (EPA-600-R-16-236ES) was issued December 13, 2016. In the report, the EPA concluded that activities throughout the hydraulic fracturing water cycle - from water withdrawal through

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disposal of produced water - “can impact [and have impacted], drinking water resources under some circumstances.” In addition to finding that spills of hydraulic fracturing chemicals had sometimes reached drinking water resources, the EPA also identified incidents of the well injection process itself contaminating drinking water resources. EPA researchers concluded that six hydraulic fracturing activities are “more likely than others to result in more frequent or more severe impacts” to drinking water: water withdrawals; chemical spills; injection of fluids into wells with inadequate mechanical integrity; injection of fluids directly into groundwater; inappropriate discharge of fracturing wastewater into streams and lakes; and storage of fracturing wastewater in unlined pits.

With the new administration, new federal requirements on hydraulic fracturing are unlikely and regulations of fracking activities will likely fall to the states. This final report, as well as its enforcement and other agency studies, depending on any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing, which events could delay or curtail production of oil and natural gas by E&P operators, some of which are our customers, and thus reduce demand for our seismic data and related services. Additionally, any such decrease in the demand for our seismic data and related services could have a material adverse effect on our revenues and results of operations.

Because of more stringent existing or any new federal, state or local legal restrictions related to the hydraulic fracturing process in areas where our E&P customers operate, those customers could incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of exploration, development or production activities, which could reduce demand for our seismic data and related services.

Seasonality and Timing Factors

Our results of operations fluctuate from quarter to quarter due to a number of factors. Our results are influenced by oil and gas industry capital expenditure budgets and spending patterns. These budgets are not necessarily spent in equal or progressive increments during the year, with spending patterns affected by individual oil and gas company requirements as well as industry-wide conditions. In addition, under our revenue recognition policy, revenue recognition from data licensing contracts is dependent upon, among other things, when the customer selects the data or when the data becomes available for delivery. As a result, our seismic data revenue does not necessarily flow evenly or progressively during a year or from year to year. Although the majority of our data licensing transactions provide for fees to us of under $750,000 per transaction, occasionally a single data license transaction from our library, including those resulting from the merger and acquisition or property sales activity of our oil and gas customers, may be substantially larger. Such large license transactions, the completion and delivery of data or an unusually large number of, or reduction in, data selections by customers can materially impact our results during a quarter, creating an impression of a revenue trend that may not be repeated in subsequent periods. In our data creation activities, weather-related or other events outside our control may impact or delay surveys during any given quarter.

Employees

As of December 31, 2016, we and our subsidiaries had 82 full-time employees, including five executive officers, 16 marketing staff and 27 technical staff. None of our employees are covered by collective bargaining agreements and we consider our relationship with our employees to be good.

Raw Material and Proprietary Information

We are not dependent on any particular raw materials, patents, trademarks or copyrights for our business operations. Our seismic data library is proprietary confidential information, which is not generally available to the public and is subject to confidentiality agreements with our employees and customers. We believe that our seismic data library is also protected by common law copyright.

Available Information

We make available free of charge, or through the “Investor Relations” section of our website at www.seitel.com, access to our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such material is filed with, or furnished to, the SEC. Our Code of Business Conduct and Ethics is also available through the “Investor Relations-Corporate Governance” section of our website or in print to anyone who requests them.

The public may read and copy any materials filed by us with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549 and may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at http://www.sec.gov.

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Item 1A. Risk Factors

The risks described below could materially and adversely affect our business and financial condition, as well as results of operations and the actual outcome of matters as to which forward-looking statements are made in this Form 10-K. The risk factors described below are not the only risks we face. Our business, financial condition and results of operations may also be affected by additional factors that are not currently known to us or that we currently consider immaterial or that are not specific to us, such as general economic conditions.

You should refer to the explanation of the qualifications and limitations on forward-looking statements included under “Cautionary Statement Regarding Forward-Looking Information” of this Form 10-K. All forward-looking statements made by us are qualified by the risk factors described below.

RISKS RELATED TO OUR BUSINESS

Our industry and the oil and gas industry are cyclical and our business could be adversely affected by the fluctuating level of capital expenditures by oil and gas companies, the level and volatility of oil and natural gas prices and global supply and demand dynamics.

Our industry and the oil and gas industry generally are subject to cyclical fluctuations. Demand for our services depends upon spending levels by oil and gas companies for exploration, production, development and field management of oil and natural gas reserves and, in the case of new seismic data creation, the willingness of these companies to forgo ownership in the seismic data. Capital expenditures by oil and gas companies for these activities depend upon several factors, including actual and forecasted prices of oil and natural gas and those companies’ short-term and long-term strategic plans. Oil and natural gas prices in turn depend on local, regional and global events or conditions that affect supply and demand for the relevant commodity. These events or conditions are generally not predictable and include, among other things:

- the level of supply and demand, the expectations regarding future supply and demand, and the actual levels of production of oil and natural gas;
- the level of prices, and expectations regarding future prices, for oil and natural gas;
- the ability or willingness of the Organization of Petroleum Exporting Countries (OPEC) to increase or decrease production levels for oil;
- oil and gas production levels by non-OPEC countries;
- worldwide political, military and economic conditions, including social and political unrest in Africa and the Middle East and domestic and foreign governmental regulations and actions (including export restrictions, sanctions, taxes, repatriations and nationalizations);
- geopolitical uncertainty in the United States and abroad;
- technological advances affecting energy exploration, development, production and consumption;
- price, availability and government subsidies for alternative fuels;
- weather, including seasonal patterns that affect regional energy demand as well as severe weather events that can disrupt supply;
- the ability of E&P companies to raise equity capital and debt financing or otherwise generate funds for exploration, development and production operations;
- the cost of exploring for, developing and producing oil and natural gas;
- the level of oil and natural gas reserves;
- the rate of discovery of new oil and gas reserves and the decline of existing oil and gas reserves; and
- the enactment and implementation of government policies, including environmental regulations and tax policies, regarding the exploration, production and development of oil and natural gas reserves and the use of fossil fuels and alternative energy sources.

Oil and natural gas prices are subject to significant volatility and there can be no assurance that oil and natural gas prices and demand will not decline again in the future. Low oil and natural gas prices and demand have resulted in decreased exploration and development spending by oil and gas companies, which could, in turn, impact our seismic data business. Additionally, increases in oil and gas prices may not always result in increased demand for our products and services or otherwise have a positive effect on our results of operations or financial condition. Our customers may adjust their exploration and development spending levels very quickly in response to any material change in oil and natural gas prices. Continued political instability (especially in the Middle East and other oil-producing regions) may lead to further significant fluctuations in demand and pricing for oil and gas or seismic data. Any future decline in oil and natural gas prices, a downturn in the oil and gas or seismic data industries, or sustained periods of reduced capital expenditures by oil and gas companies as a result of factors which are beyond our control, could have a material adverse effect on our results of operations and cash flow.

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Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, which could adversely impact our revenues by decreasing the demand for our seismic data and related services.

Hydraulic fracturing is the process used by E&P operators of drilling and injecting fluid into a wellbore at high pressure in order to fracture rocks to release the gas or petroleum inside. The process involves the high pressure injection of water, proppants (typically sand) and chemicals into subsurface formations to stimulate gas and petroleum production. Due to public concerns that hydraulic fracturing may adversely affect drinking water supplies, increase emissions of perceived greenhouse gases and/or adversely affect local community infrastructure, including, for example, through increased truck traffic, hydraulic fracturing has become the subject of controversy and increased opposition by certain environmental groups. It has been the subject of numerous private and governmental studies, and has triggered increased governmental regulation. While the process is typically regulated by state oil and gas commissions, several federal agencies including the EPA and BLM, have asserted regulatory authority over certain aspects of the process. Congress has from time to time considered the adoption of legislation to provide for federal regulation of hydraulic fracturing and regional or state agencies with control over the withdrawal of water used in hydraulic fracturing activities may impose stringent conditions on, or delay or prohibit, such water withdrawals. At the state level, a growing number of states have adopted legal requirements that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing activities. In addition, local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Furthermore, several federal governmental agencies including the EPA are working with states and other key stakeholders to assess adverse impacts that hydraulic fracturing may have on drinking water or groundwater sources or otherwise to help ensure that natural gas extraction does not come at the expense of public health and the environment. In June 2015, the EPA released its draft report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that hydraulic fracturing activities have not lead to widespread, systemic impacts on drinking water sources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water sources. However, in January 2016, the EPA’s Science Advisory Board provided its comments on the draft study, indicating its concern that EPA’s conclusion of no widespread, systemic impacts on drinking water sources arising from fracturing activities did not reflect the uncertainties and data limitations associated with such impacts, as described in the body of the draft report. The EPA's final report, “Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States,” (EPA-600-R-16-236ES) was issued December 13, 2016 and clarified the findings of the agency’s June 2015 draft report. The EPA concluded that activities throughout the hydraulic fracturing water cycle - from water withdrawal through disposal of produced water - “can impact [and have impacted], drinking water resources under some circumstances.” In addition to finding that spills of hydraulic fracturing chemicals had sometimes reached drinking water resources, the EPA also identified incidents of the well injection process itself contaminating drinking water resources. One such incident resulted from improper well cementing, while another stemmed from a burst production casing. EPA researchers concluded that six hydraulic fracturing activities are “more likely than others to result in more frequent or more severe impacts” to drinking water: water withdrawals; chemical spills; injection of fluids into wells with inadequate mechanical integrity; injection of fluids directly into groundwater; inappropriate discharge of fracturing wastewater into streams and lakes; and storage of fracturing wastewater in unlined pits.

In a different political environment, regulators might have relied on the final report to support additional rulemaking at the federal level to protect drinking water resources from hydraulic fracturing impacts. With the new administration, new federal requirements on hydraulic fracturing are unlikely and regulation of fracking activities will likely fall to the states which may, under the incoming administration, not be anxious to issue new regulations or take aggressive enforcement action. According to the EPA, the understanding of potential impacts from hydraulic fracturing on drinking water resources will continue to improve over time as new information becomes available. This final report, as well as other studies, depending on any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing, which events could delay or curtail production of oil and natural gas by E&P operators, some of which are our customers, and thus reduce demand for our seismic data and related services. Additionally, any such decrease in the demand for our seismic data and related services could have a material adverse effect on our revenues and results of operations.

Because of more stringent existing or any new federal, state or local legal restrictions related to the hydraulic fracturing process in areas where our E&P customers operate, those customers could incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of exploration, development or production activities, which could reduce demand for our seismic data and related services.

Economic conditions could adversely affect demand for our seismic data and related services and could increase our credit risk of customer non-payment.

Prices for oil and natural gas fluctuate widely. Prolonged or substantial declines in crude oil and/or natural gas prices have resulted in many oil and gas companies significantly reducing their levels of capital spending, and such reduction could

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intensify which could result in reduced demand for our seismic data and related services as our customers' operating cash flow decreases and the borrowing bases under their oil and gas reserve-based credit facilities are reduced. Prolonged or substantial declines in commodity prices could also result in decreases in our customers' liquidity and capital resources, which could increase our credit risk of non-payment from such customers.

We are dependent on the availability of internally generated cash flow and financing alternatives to cover the costs of acquiring and processing seismic data for our data library that are not underwritten by our customers.

We invest additional capital in acquiring and processing new seismic data to expand our data library. A significant portion of these costs is underwritten by our customers, while the remainder is financed through the use of internally generated cash flow and other financing sources. We may use bank or commercial debt, the issuance of equity or debt securities or any combination thereof to finance these costs. There can be no assurance that our customers will continue to underwrite these costs at historical levels, or that we will have available internally generated funds or will be successful in obtaining sufficient capital through additional financing or other transactions, if required, on terms acceptable to us, to continue to invest in acquiring new seismic data. Any substantial alteration of or increase in our capitalization through the issuance of debt securities may significantly increase our leverage and decrease our financial flexibility. If we are unable to obtain financing on acceptable terms or at all, we may be forced to finance our operations with only internally generated funds, and if we are unable to generate sufficient funds internally, we may be unable to execute our business strategies.

Our working capital needs are difficult to forecast and may vary significantly, which could require us to seek financing that we may not be able to obtain on satisfactory terms, or at all.

Our working capital needs are difficult to predict with certainty as they fluctuate from quarter to quarter based on the level of activity of our business. This difficulty is due primarily to the timing of our projects, our customers' budgetary cycles and our receipt of payment. We may therefore be subject to significant and rapid increases in our working capital needs that could require us to seek financing sources. Restrictions in our debt agreement may impair our ability to obtain other sources of financing, and access to sources of financing may not be available on terms acceptable to us, or at all.

We have invested, and expect to continue to invest, significant amounts of money in acquiring and processing seismic data for our seismic data library without knowing precisely how much of this seismic data we will be able to license or when and at what price we will be able to license such data.

We invest significant amounts of money in acquiring and processing seismic data for our seismic data library, albeit at a reduced level in low commodity price environments. By making such investments, we are exposed to the following risks:

- We may not fully recover our costs of acquiring and processing seismic data through future licensing of data that we own. The amounts of these data sales are uncertain and depend on a variety of factors, many of which are beyond our control.
- The timing of these sales is unpredictable and can vary greatly from quarter to quarter. The costs of each survey are capitalized and then amortized over the expected book life of the data. This amortization will affect our earnings and when combined with the sporadic nature of sales, will result in increased earnings volatility.
- Regulatory changes that affect companies' ability to drill, either generally or in a specific location where we have acquired seismic data, could materially adversely affect the value of the seismic data contained in our library. In addition, technology changes could also make existing data sets less desirable or obsolete.
- The value of our data could be significantly adversely affected if any material adverse change occurs in the general prospects for oil and gas exploration, development and production activities.
- The cost estimates upon which we base our pre-commitments of funding could be incorrect, which could result in losses that have a material adverse effect on our financial condition and results of operations.

- Underwriting commitments of funding are subject to the creditworthiness of our customers. In the event that a customer refuses or is unable to pay its commitment, we could lose a material amount of money.

The cyclical nature of the oil and gas industry can have a significant effect on our revenues and profitability. Historically, oil and natural gas prices, as well as the level of exploration and developmental activity, have fluctuated significantly. These fluctuations have in the past, and may in the future, adversely affect our business. We are unable to predict future oil and natural gas prices or the level of oil and gas industry activity. Prolonged periods of low commodity prices depress development activity, adversely affecting the demand for our products and services and our financial condition and results of operations.

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We rely on developing and acquiring proprietary data, and if we are unable to maintain its confidentiality, we could be materially negatively affected.

Our customer data license agreements and acquisition agreements identify our proprietary, confidential information and require that such information is restricted to the licensee and must be kept confidential. However, we cannot ensure that unauthorized use, misappropriation or disclosure will not occur. The rise in bankruptcy filings in 2016 and in recent months by some of our customers places our data license agreements at risk of unauthorized assumption and/or assignment. If we are unable to prevent the assumption and/or assignment or otherwise maintain the confidentiality of our proprietary, confidential information, we could be materially negatively affected.
Our business could be negatively affected by security threats, including cybersecurity threats, and other disruptions.
We face various security threats, including cybersecurity threats, to gain unauthorized access to sensitive information or to render data or systems unusable. While we have redundant security systems in place to protect our sensitive data, the potential for such security threats subjects our operations to increased risks that could have a material adverse effect on our business. Designing and implementing procedures and controls to monitor and mitigate security threats and to increase security for our information and infrastructure is capital intensive, and there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability for asserted claims.

Our business could be adversely affected by the failure of our customers to fulfill their obligations to reimburse us for the underwritten portion of third-party contractor costs.

A substantial portion of our seismic acquisition project costs, including third-party project costs, is underwritten by our customers. Historically, we have targeted an average of 60% to 70% underwriting levels for new seismic acquisition projects on an aggregate basis. In low commodity price environments, we may target higher underwriting levels, which may increase the risk that our customers fail to fulfill their obligations to reimburse us. On occasion, when our underwriting customer owns other appealing seismic data that we want to obtain, we may decide to take ownership in this data to cover a portion of the customer's underwriting obligation. In the event that underwriters for such projects fail to fulfill their obligations with respect to such underwriting commitments, we would continue to be obligated to satisfy our payment obligations to third-party contractors.

We rely on third-party contractors to shoot new data.

We do not employ seismic crews or own any seismic survey equipment but contract, as needed, multiple third-party contractors with qualified equipment, personnel and expertise to shoot new data. Any failure, however, by these third-party contractors to meet the requisite industry quality, safety and environmental standards could result in our liability to third parties and have a material adverse effect on our business, reputation, financial condition and results of operations. Moreover, if we fail to retain our third-party contractors or obtain replacements on favorable terms or at all, our business and operating results may be materially and adversely affected.

We may be held liable for the actions of third-party contractors.

We often engage a number of third-party contractors to perform specific services and provide products and qualified personnel in connection with our operations. There can be no assurance that we will not be held liable for the actions or inactions of these contractors. In addition, contractors may cause damage or injury to our personnel and property or third-party personnel or property, which may not be fully covered by insurance.

Competition for the acquisition of new seismic data is intense.

There are a number of geophysical services companies that create, market and license seismic data and maintain seismic libraries. Competition for acquisition of new seismic data among geophysical service providers in the United States and Canada historically has been, and we expect will continue to be, intense. Certain competitors have significantly greater financial and other resources than we do. These larger and better-financed operators could enjoy an advantage over us in a competitive environment for the limited opportunities to acquire new data.

Our operating results and cash flows are subject to fluctuations due to circumstances that are beyond our control.

Our operating results and cash flows from operations have in the past, and may in the future, vary in material respects from period to period. Factors that have and could cause variations include, but are not limited to, (1) timing of the receipt and commencement of contracts for data acquisition, (2) our customers' budgetary cycles and their effect on the demand for geophysical products and services, (3) seasonal factors, (4) weather conditions, (5) the timing of cash resales and selections of significant geophysical data from our data library, which are not typically made in a linear or consistent pattern and (6) technological or regulatory changes. These revenue fluctuations could produce unexpected adverse operating results in any period.

There are risks and uncertainties associated with our operations in Mexico.

Historically, Mexico has been subject to political and social instability, and our operations in Mexico may expose us to various levels of foreign political, economic and other risks and uncertainties. These risks and uncertainties include, but are not limited to, terrorism, hostage taking, military repression, extreme fluctuations in currency exchange rates, high rates of inflation, labor unrest, the risk of war or civil unrest, expropriation and nationalization, renegotiation or nullification of existing concessions,
licenses, permits, approvals and contracts, changes in taxation policies, restrictions on foreign exchange and repatriation, changing political conditions and currency controls. Furthermore, change and uncertainty in Mexico could lead to changes in
existing governmental laws and regulations affecting oil and gas exploration and production, which could adversely impact demand for our seismic data. Shifts in political conditions may increase the cost of conducting our business in Mexico.

A reduction in demand for our seismic data may result in an impairment of the value of our seismic data library.

Reduced demand, future sales or cash flows may result in a requirement to increase amortization rates or record impairment charges to reduce the carrying value of our data library. Such increases or charges, if required, could be material to operating results in the periods in which they are recorded. For purposes of evaluating potential impairment losses, we estimate the future cash flows attributable to a library component by evaluating historical and recent revenue trends, oil and gas prospectivity in particular regions, general economic conditions affecting our customer base, expected changes in technology and other factors that we deem relevant. As a result of these factors, among others, estimations of future cash flows are highly subjective, inherently imprecise and can fluctuate materially from period to period. Accordingly, if conditions change in the future, we may record impairment losses relative to our seismic data library, which could materially affect our results of operations in any particular reporting period.

Failure to meet cash flow projections may result in goodwill impairment charges.

We perform an annual assessment of the recoverability of goodwill. Additionally, we assess goodwill for impairment whenever events or changes in circumstances indicate that such carrying values may not be recoverable. If required to perform a goodwill impairment test, we rely on discounted cash flow analysis, which requires significant judgments and estimates about our future operations, to develop our estimates of fair value. If these projected cash flows change materially, we may be required to record impairment losses relative to goodwill which could be material to our results of operations in any particular reporting period.

Our Canadian operations subject us to currency translation risk, which could cause our results to fluctuate significantly from period to period.

A portion of our revenues is derived from our Canadian activities and operations. As a result, we translate the results of our Canadian operations and financial condition into U.S. dollars. Therefore, our reported results of operations and financial condition are subject to changes in the exchange rate between the two currencies. Fluctuations in foreign currency exchange rates could affect our revenue, expenses and operating margins. Assets and liabilities of our Canadian operations are translated from Canadian dollars into U.S. dollars at the exchange rates in effect at the relevant balance sheet date, and revenue and expenses of our Canadian operations are translated from Canadian dollars into U.S. dollars at exchange rates as of the dates on which they are recognized. Translation adjustments related to assets and liabilities are included in accumulated other comprehensive income in stockholder's equity. Realized gains and losses on translation of our Canadian operations into U.S. dollars are included in net income. Currently, we do not hedge our exposure to changes in foreign exchange rates.

We may be unable to attract and retain key employees.

Our success depends upon our ability to attract and retain highly skilled geophysical professionals and other technical personnel. Failure to continue attracting and retaining these individuals could adversely affect our ability to compete in the geophysical services industry. We may confront significant and potentially adverse competition for key personnel.

Our success also depends to a significant extent upon the abilities and efforts of members of our senior executive management, the loss of whom could adversely affect our business. Senior executives, which include our Chief Executive Officer and President, Chief Financial Officer, Chief Technology Officer and President of Seitel Canada Ltd., and President of Seitel Data, Ltd. have employment agreements with us. We cannot be certain that our senior executives will continue to be employed by us for an indefinite period of time and, if they do, how long they will remain so employed. Any inability to attract and retain key management personnel could have a material adverse effect on our ability to manage our business properly.

We are subject to certain types of claims in the ordinary course of business.

We may become involved in, named as a party to, or be the subject of, various legal matters, including regulatory proceedings, and litigation asserting claims for personal injury, property damage, trespass, and contract disputes. The outcome of pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and as a result, could have a material adverse effect on our assets, liabilities, business, financial condition, results of operations, cash flows and future prospects.

Current and future government regulation may negatively impact demand for our products and services and increase our cost of conducting business.

The conduct of our business and the demand for our products and services are subject to various laws and regulations administered by federal, provincial, state and local governmental authorities and agencies in the United States and Canada. We may incur significant costs and delays in order to attain or maintain compliance with these legal requirements. These laws and regulations may impose numerous obligations that are applicable to our operations including:

- the acquisition of permits before commencing regulated activities;
- the limitation or prohibition of seismic activities in environmentally sensitive or protected areas such as wetlands or wilderness areas; and
- the application of specific health and safety criteria addressing worker protection.

Further, failure to comply with laws, regulations, permits, and First Nations and Native Americans protocol may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions limiting or preventing some or all of our operations. In the oil and gas industry more generally, protracted approval processes, including consultations with First Nations in Canada and Native Americans in the U.S., for proposed projects could dampen investment in new projects, and thereby negatively impact demand for our products and services.

Additionally, these laws, regulations and government policies may change as a result of changing political, economic or social climate. Such changes may alter the environment in which we do business as well as the demand for our products and services and, therefore, may impact the results of our operations or increase our liabilities. More stringent new and future laws, regulations and policies concerning hydraulic fracturing activities, emissions of greenhouse gases and the use of renewable energy sources rather than fossil fuels could negatively impact the operations of our customers. Further future changes in these and other laws and regulations or the imposition of additional regulations that have a negative financial impact on E&P operators, some of which are our customers, could result in decreased demand for our products and services. Moreover, complying with more stringent regulations could cause an increase in our operating expenses, which could adversely affect our business.

Technological changes not available to us could adversely affect our business.

New data acquisition or processing technologies may be developed. New and enhanced products and services introduced by one of our competitors may gain market acceptance and, if not available to us, may adversely affect our business.

Our internal controls for financial reporting and our disclosure controls and procedures may not prevent all possible errors that could occur.

Our Chief Executive Officer and President and our Chief Financial Officer evaluate, on a quarterly basis, our internal controls for financial reporting and our disclosure controls and procedures, which includes a review of the objectives, design, implementation and effect of the controls in respect of the information generated for use in our periodic reports. In the course of

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our controls evaluation, we seek to identify data errors, control problems and confirm that appropriate corrective action, including process improvements, are being undertaken. The overall goals of these various evaluation activities are to monitor our internal controls for financial reporting, to monitor our disclosure controls and procedures, and to make modifications as necessary. Our intent in this regard is that our internal controls for financial reporting and our disclosure controls and procedures will be maintained as dynamic systems that change (including with improvements and corrections) as conditions warrant.

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be satisfied. Our management has concluded that our internal controls for financial reporting and our disclosure controls and procedures are designed to give a reasonable assurance that they are effective to achieve their objectives. We cannot provide absolute assurance that we have detected all possible control issues. These inherent limitations include the possibility that judgments in our decision-making could be faulty, and that isolated breakdowns could occur because of simple human error or mistake. The design of our system of controls is based, in part, upon certain assumptions regarding the likelihood of future events, and there can be no assurance that any design will succeed absolutely in achieving our stated goals under all potential future or unforeseeable conditions. In light of the inherent limitations in a cost-effective control system, misstatements due to error or fraud could occur and not be detected. Breakdowns in our internal controls and procedures could occur in the future, and any such breakdowns could have an adverse effect on our business.

Tax authorities may reassess our tax calculations, or may change their administrative policies to our detriment.

There can be no assurance that the relevant tax authorities will agree with how we calculate our income for tax purposes or that such tax authorities will not change their administrative practices to our detriment.

RISKS RELATED TO OUR INDEBTEDNESS

Our level of indebtedness could adversely affect our financial condition and our ability to fulfill our payment obligations and operate our business.

As of December 31, 2016, we had approximately $251.5 million of total outstanding indebtedness, including $1.5 million of capital leases. Our 2017 consolidated annual debt service requirements are expected to aggregate approximately $24.1 million. We may also incur additional indebtedness in the future.

Our level of indebtedness could have negative consequences to us, including:

- we may have difficulty satisfying our obligations with respect to our debt;
- we may have difficulty obtaining financing in the future for working capital, capital expenditures, acquisitions or other purposes;
- we may need to use all, or a substantial portion, of our available cash flow to pay interest and principal on our debt, which will reduce the amount of money available to finance our operations and other business activities;
- our vulnerability to general economic downturns and adverse industry conditions could increase;
- our flexibility in planning for, or reacting to, changes in our business and in our industry in general could be limited;
- our amount of debt and the amount we must pay to service our debt obligations could place us at a competitive disadvantage compared to our competitors that have less debt;
- our customers may react adversely to our significant debt level and seek or develop alternative licensors or suppliers;
- we may have insufficient funds, and our debt level may also restrict us from raising the funds necessary to repurchase all of the notes tendered to us upon the occurrence of a change of control, which would constitute an event of default under the notes; and
- our failure to comply with the restrictive covenants in our debt instruments which, among other things, limit our ability to incur debt and sell assets, could result in an event of default which, if not cured or waived, could have a material adverse effect on our business or prospects.

Our level of indebtedness requires that we use a substantial portion of our cash flow from operations to pay principal of, and interest on, our indebtedness, which will reduce the availability of cash to fund working capital requirements, capital expenditures, research and development and other general corporate or business activities, including future acquisitions.

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The indenture governing our $250.0 million aggregate principal amount of 9½% senior notes due 2019 ("the 9½% Senior Notes") contains a number of restrictive covenants, which limit our ability to finance future operations or capital needs or engage in other business activities that may be in our interest.

The indenture governing our 9½% Senior Notes imposes, and the terms of any future indebtedness may impose, operating and other restrictions on us and our subsidiaries. Such restrictions affect or will affect, and in many respects limit or prohibit, among other things, our ability and the ability of certain of our subsidiaries to:

- incur additional indebtedness;
- create liens;
- pay dividends and make other distributions in respect of our capital stock;
- redeem our capital stock;
- make investments or certain other restricted payments;
- sell certain kinds of assets;
- enter into transactions with affiliates; and
- effect mergers or consolidations.

The restrictions contained in the indenture governing our 9½% Senior Notes could:

- limit our ability to plan for or react to market or economic conditions or meet capital needs or otherwise restrict our activities or business plans; and
- adversely affect our ability to finance our operations, acquisitions, investments or strategic alliances or other capital needs or to engage in other business activities that would be in our interest.

A breach of any of these covenants could result in a default under the indenture governing our 9½% Senior Notes. If an event of default occurs, the lenders could elect to:

- declare all borrowings outstanding, together with accrued and unpaid interest, to be immediately due and payable; or
- require us to apply all of our available cash to repay the borrowings.

If we were unable to repay or otherwise refinance these borrowings when due, we cannot assure that sufficient assets will remain to repay the 9½% Senior Notes.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Our corporate headquarters are located at 10811 South Westview Circle Drive, Suite 100, Building C, Houston, Texas 77043, which also serves as administrative and financial offices, warehouse space and storage. We maintain domestic marketing offices in Dallas, Texas; Denver, Colorado; New Orleans, Louisiana and Oklahoma City, Oklahoma. We also lease office and warehouse space in two separate locations in Calgary, Alberta, Canada, where our Canadian operations are headquartered. We consider our business facilities adequate and suitable for our present and anticipated future needs, but may seek to expand our facilities from time to time.

The following table sets forth the locations of our offices and warehouses, the approximate square footage of space we maintain at such locations, our use of such space and whether it is owned or leased by us.

Location	Approximate Square Footage	Use	Owned/Leased
Houston, Texas	80,125	Administrative; Financial; Marketing; Operations; Warehouse	Leased
Dallas, Texas	194	Marketing	Leased
Denver, Colorado	1,506	Marketing	Leased
New Orleans, Louisiana	364	Marketing	Leased

Oklahoma City, Oklahoma	234	Marketing	Leased
Calgary, Alberta, Canada	14,909	Administrative; Financial; Marketing; Operations	Leased
Calgary, Alberta, Canada	42,985	Warehouse	Leased

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Item 3. Legal Proceedings

We are involved from time to time in ordinary, routine claims and lawsuits incidental to our business. In the opinion of management, uninsured losses, if any, resulting from the ultimate resolution of these matters should not be material to our financial position, results of operations or cash flows. However, it is not possible to predict or determine the outcomes of the legal actions brought against us or by us, or to provide an estimate of all additional losses, if any, that may arise. At December 31, 2016, we have recorded the estimated amount of potential exposure we may have with respect to litigation and claims. Such amounts are not material to the financial statements.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Market Information

Our common stock is privately held and there is no established public trading market for our common stock. As of December 31, 2016, there was one holder of record of our 100 shares of common stock, $0.001 par value per share.

Dividend Policy

We have not declared or paid any cash dividends on our common stock during our two most recent fiscal years. We do not intend to declare or pay any cash dividends on our common stock in the foreseeable future. Covenants within our 9½% Senior Notes restrict our ability to pay cash dividends on our capital stock. Future declaration and payment of cash dividends, if any, on our common stock will be determined in light of factors deemed relevant by our board of directors, including our earnings, operations, capital requirements and financial condition and restrictions in our financing agreements.

Item 6. Selected Financial Data

The following table summarizes certain historical consolidated financial data of the Company and is qualified in its entirety by the more detailed consolidated financial statements and notes thereto included herein (in thousands, except shares).

	Year Ended December 31,				
	2016	2015	2014	2013	2012
Statement of Operations Data:					
Revenue	$94,546	$100,252	$198,037	$202,874	$240,458
Expenses and costs:					
Depreciation and amortization	75,078	80,923	121,023	121,598	139,754
Cost of sales	76	195	304	475	464
Selling, general and administrative	24,119	22,184	29,799	25,971	29,088
	99,273	103,302	151,126	148,044	169,306
Income (loss) from operations	(4,727)	(3,050)	46,911	54,830	71,152
Interest expense, net	(24,967)	(25,390)	(25,029)	(27,851)	(29,011)
Foreign currency exchange gains (losses)	109	(1,650)	(1,974)	(2,222)	681
Loss on early extinguishment of debt	—	—	—	(1,504)	—
Gain on sale of marketable securities	—	—	—	—	230
Other income	1,765	5	63	488	780

Income (loss) before income taxes	(27,820)	(30,085)	19,971	23,741	43,832
Provision (benefit) for income taxes	(3,396)	79,905	10,293	(89,940)	6,782
Net income (loss)	$(24,424)	$(109,990)	$9,678	$113,681	$37,050

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	As of December 31,				
	2016	2015	2014	2013	2012
Balance Sheet Data:					
Cash and cash equivalents	$55,997	$52,675	$59,175	$31,353	$61,891
Seismic data library, net	115,922	161,363	165,079	195,778	180,117
Total assets (1)	385,171	421,487	574,400	589,207	548,896
Total debt (1)	248,367	247,357	246,863	246,370	276,294
Stockholder’s equity	101,059	122,216	253,089	254,956	150,358
Common shares outstanding	100	100	100	100	100

(1) Total assets and total debt for fiscal year-end 2015, 2014, 2013 and 2012 have been restated to reflect the adoption of Financial Accounting Standards Board Accounting Standards Update No. 2015-03 effective January 1, 2016. The new standard changed the presentation of debt issuance costs from an asset to a direct deduction from the related liability.

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

The following discussion should be read in conjunction with our consolidated financial statements and the related notes to the consolidated financial statements included elsewhere in this document.

Overview

General

Our products and services are used by E&P companies in oil and gas exploration and development efforts to increase the probability of drilling success, to better delineate existing oil and gas fields and to augment their reservoir completion and management techniques. In unconventional plays, E&P companies use seismic data as a development tool to better identify efficient drilling plans and maximize production by identifying and understanding a series of critical characteristics of the targeted resource. We own an extensive library of onshore and offshore seismic data that we offer for license to E&P companies. We believe that our library of onshore seismic data is one of the largest available for licensing in North America. We generate revenue primarily by licensing data from our data library and from new data creation products, which are substantially underwritten or paid for by our clients. By participating in underwritten, non-exclusive surveys or purchasing licenses to existing data, E&P companies can obtain access to surveys at reduced costs as compared to acquiring seismic data on a proprietary basis.

Our primary areas of focus are onshore United States and Canada and, to a lesser extent, offshore U.S. Gulf of Mexico. Our offshore seismic data is primarily located in the shallow waters of the U.S. Gulf of Mexico and generates a small percentage of our revenue. As a result of the energy reform in Mexico, we began to expand our data library coverage into Mexico in 2015.

We are anticipating 2017 to be the first year of recovery in upstream capital spending due to improved commodity prices. However, uncertainty remains as to the effectiveness and duration of the concurrent OPEC and non-OPEC production cuts, which could influence oil prices in either direction. Also, the potential for efficiency gains and cost reductions from non-OPEC producers in the higher price environment could result in additional volumes of supply that could put downward pressure on oil prices. We remain cautiously optimistic that we will see improvements in seismic spending from our E&P clients in 2017. We do, however, believe that seismic spending will continue to fluctuate quarter to quarter. We believe our asset-light business model, variable cost structure and streamlined support structure allow us to respond to changes, both positive and negative, in the industry environment.

Principal Factors Affecting Our Business

Our business is dependent upon a variety of factors, many of which are beyond our control. The following are those that we consider to be principal factors affecting our business.

Demand for Seismic Data: Demand for our products and services is cyclical due to the nature of the oil and gas industry. In particular, demand for our seismic data services depends upon exploration, production, development and field management spending by E&P companies and, in the case of new data creation, the willingness of these companies to forgo ownership in the seismic data. Capital expenditures by E&P companies depend upon several factors, including actual and forecasted oil and natural gas commodity prices, prospect availability and the companies' own short-term and long-term strategic plans. These capital expenditures may also be affected by worldwide economic or industry-wide conditions.

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Merger and Acquisition/Joint Venture Activity: Merger and acquisition activity continues to occur within our client base. This activity could have a negative impact on seismic companies that operate in markets with a limited number of participating clients. However, we believe that, over time, this activity could have a positive impact on our business as it should generate re-licensing fees, result in increased vitality in the trading of mineral interests and result in the creation of new independent customers through the rationalization of staff within those companies affected by this activity.
Exploiting unconventional plays is a capital intensive endeavor and many technically proficient E&P companies remain capital constrained. These companies find themselves needing to sell their positions to, or create partnerships with, large well-capitalized companies in order to develop their recoverable resource base. These joint venture partners or new owners will often need to purchase licenses to our seismic data for their own use.

North America Drilling Activity: After significant declines in North America drilling activity in 2015 and the early part of 2016, the North American rig count began to improve in the second quarter of 2016. Since the low of 422 rigs in May 2016, the North American land rig count has improved to 1,036 as of January 27, 2017, an increase of 145%. The rig count is forecast to continue to rise throughout 2017 with continued strong directional drilling activity.

Availability of Capital for Our Customers: The continued low oil and gas prices have caused a reduction in cash flows for our customers. Many E&P companies rely on revolving credit to finance their day-to-day operations. These credit facilities have borrowing bases that are tied to the net present value of their reserves. Low oil prices have decreased the value of those reserves and, as a result, the borrowing bases under such facilities have been reduced. Reductions in cash flows resulting from lower commodity prices, along with the reduced availability of credit and increased costs of borrowing, could have a material impact on the ability of such companies to obtain funding necessary to purchase our seismic data.
Government Regulation: Our operations are subject to a variety of federal, provincial, state, foreign and local laws and regulations, including environmental and health and safety laws. We invest financial and managerial resources to comply with these laws and related permit requirements. Modification of existing laws or regulations and the adoption of new laws or regulations limiting or increasing exploration or production activities by oil and gas companies may have a material effect on our business operations.
Key Performance Measures
Management considers, among others, the following performance and financial measures in evaluating and managing our operating performance and financial condition. Some of these measures are not calculated in accordance with United States generally accepted accounting principles, or GAAP. Generally, a non-GAAP measure is a numerical measure of a company’s performance, financial position or cash flows that either excludes or includes amounts that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with GAAP. These non-GAAP measures are intended to supplement the presentation of our financial results that are prepared in accordance with GAAP and should not be considered substitutes for GAAP financial measures.
Cash Resales
Cash resales represent new contracts for data licenses from our library, including data currently in progress, payable in cash. We believe cash resales are an important measure of our operating performance and are useful in assessing overall industry and client activity. Cash resales are likely to fluctuate quarter to quarter as they do not require the longer planning and lead times necessary for new data creation.
Cash resales for the three years ended December 31, 2016 were as follows (in thousands):

	Year Ended December 31,		
	2016	2015	2014
Cash resales	$59,404	$44,350	$123,530

Cash EBITDA

Cash EBITDA represents cash generated from licensing data from our seismic library net of recurring cash operating expenses. We believe this measure is helpful in determining the level of cash from operations we have available for debt service and funding of capital expenditures (net of the portion funded or underwritten by our customers). Cash EBITDA includes cash resales plus all other cash revenues other than from data acquisitions, less cost of goods sold and cash selling, general and administrative expenses (excluding severance and other non-routine costs).

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The following is a quantitative reconciliation of this non-GAAP financial measure to the most directly comparable GAAP financial measure, cash flows from operating activities (in thousands):

	Year Ended December 31,		
	2016	2015	2014
Cash EBITDA	$39,362	$25,263	$98,943
Add (subtract) other components not included in cash EBITDA:			
Cash acquisition underwriting revenue	21,329	42,566	59,922
Revenue recognition adjustments from contracts payable in cash	8,413	4,107	9,514
Severance and other non-routine costs	(1,984)	(663)	(980)
Interest expense, net	(24,967)	(25,390)	(25,029)
Amortization of deferred financing costs	1,224	1,200	1,090
Increase (decrease) in allowance for doubtful accounts	(20)	4	(337)
Other cash operating income	14	5	78
Current income tax expense	(561)	(193)	(1,020)
Changes in operating working capital	(12,267)	25,737	(17,836)
Net cash provided by operating activities	$30,543	$72,636	$124,345

Growth of our Seismic Data Library

We regularly add to our seismic data library through four different methods: (1) recording new data, (2) buying ownership of existing data for cash, (3) obtaining ownership of existing data through non-monetary exchanges and (4) creating new value-added products from existing data within our library. For the years ended December 31, 2016, 2015 and 2014, we completed the addition of approximately 1,500 square miles, 1,250 square miles and 1,600 square miles, respectively, of seismic data to our library. As of February 13, 2017, we had 250 square miles of seismic data in progress.

Critical Accounting Policies

We operate in one business segment, which consists of seismic data acquisition, seismic data licensing, seismic data processing and seismic reproduction services.

We prepare our consolidated financial statements and the accompanying notes in conformity with GAAP, which requires management to make estimates and assumptions about future events that affect the reported amounts in the consolidated financial statements and the accompanying notes. We identify certain accounting policies as critical based on, among other things, their impact on the portrayal of our financial condition and results of operations and the degree of difficulty, subjectivity and complexity in their deployment. Notes A and B of the Notes to the Consolidated Financial Statements include a summary of the significant accounting policies used in the preparation of the accompanying consolidated financial statements. The following is a brief discussion of our most critical accounting policies.

Revenue Recognition

Revenue from Data Acquisition

We generate revenue when we create a new seismic survey that is initially licensed by one or more of our customers to use the resulting data. Contracts which are signed up to the time we make a firm commitment to create the new seismic survey are considered acquisition underwriting. Acquisition underwriting revenue is recognized throughout the creation period using the proportional performance method based upon costs incurred and work performed to date as a percentage of total estimated costs and work required. Management believes that this method is the most reliable and representative measure of progress for our data creation projects. The customers paying for the initial licenses receive legally enforceable rights to any resulting product of the specific activities required to complete the survey. The customers also receive access to and use of the newly acquired, processed data.

Revenue from Non-Exclusive Data Licenses

We recognize a substantial portion of our revenue from licensing of data once it is available for delivery. Revenue from the non-exclusive licensing of seismic data is recognized when the following criteria are met:

- we have an agreement with the customer that is validated by a signed contract;
- the sales price is fixed and determinable;
- collection is reasonably assured;

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•the customer has selected the specific data or the contract has expired without full selection;
•the data is currently available for delivery; and
•the license term has begun.

Copies of the licensed data are available to the customer immediately upon request.

For licenses that have been invoiced for which payment is due or has been received, but that have not met the aforementioned criteria, revenue is deferred along with the related direct costs (primarily consisting of sales commissions). This normally occurs under the library card, review and possession or review only license contracts because the data selection may occur over time. Additionally, if the contract allows licensing of data that is not currently available or enhancements, modifications or additions to the data are required per the contract, revenue is deferred until such time that the data is available.

Revenue from Non-Monetary Exchanges

In certain cases, we will take ownership of a customer's seismic data or revenue interest (collectively referred to as "data") or receive advanced data processing services in exchange for (i) a non-exclusive license to selected seismic data from our library, (ii) as partial consideration for the underwriting of new data acquisition or (iii) reproduction or data processing services. These exchanges are referred to as non-monetary exchanges. In non-monetary exchange transactions, we record a data library asset for the data received or processed at the time the contract is entered into or the data is completed, as applicable, and recognize revenue on the transaction in equal value in accordance with our policies on revenue from data licenses or data acquisition or as services are provided, as applicable. These transactions are valued at the fair value of the data received or the fair value of the license granted or services provided, whichever is more readily determinable.

Seismic Data Library

Costs associated with creating, acquiring or purchasing seismic data are capitalized and amortized principally on the income forecast method subject to a straight-line amortization period of four years, applied on a quarterly basis at the individual survey level.

Data Library Amortization

We amortize each survey in our seismic data library using the greater of the amortization that would result from the application of the income forecast method to each survey's revenue (subject to a minimum amortization rate) or a straight-line basis over four years commencing at the time such survey is completed and available for licensing to customers on a non-exclusive basis. Due to the subjectivity inherent in the income forecast amortization method, this amortization policy ensures a minimum level of amortization will be recorded if sales of the specific data do not occur as expected.

We apply the income forecast method by forecasting the ultimate revenue expected to be derived from a particular data library component over the estimated useful life of each survey comprising part of such component. We make this forecast annually and review it quarterly. If, during any such review, we determine that the ultimate revenue for a library component is expected to be significantly different than the most recent estimate of total revenue for such library component, we revise the amortization rate attributable to future revenue from each survey in such component. The Company applies a minimum amortization rate of 70%.

The greater of the income forecast or straight-line amortization policy is applied quarterly on a cumulative basis at the individual survey level. Under this policy, we first record amortization using the income forecast method. The cumulative amortization recorded for each survey is then compared with the cumulative straight-line amortization. If the cumulative straight-line amortization is higher for any specific survey, additional amortization expense is recorded, resulting in accumulated amortization being equal to the cumulative straight-line amortization for such survey. This requirement is applied regardless of future-year revenue estimates for the library component of which the survey is a part and does not consider the existence of deferred revenue with respect to the library component or to any survey.

Seismic Data Library Impairment

We evaluate our seismic data library for impairment by grouping individual surveys into components based on our operations and geological and geographical trends. We believe that these library components constitute the lowest levels of independently identifiable cash flows. We evaluate our seismic data library investment for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable.

The impairment evaluation is based first on a comparison of the undiscounted future cash flows over each component's remaining estimated useful life with the carrying value of each library component. If the undiscounted cash flows are equal to or greater than the carrying value of such component, no impairment is recorded. If undiscounted cash flows are less than the carrying value of any component, the forecast of future cash flows related to such component is discounted to fair value and

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compared with such component's carrying amount. The difference between the library component's carrying amount and the discounted future value of the expected revenue stream is recorded as an impairment charge.

The estimation of future cash flows and fair value is highly subjective and inherently imprecise. Estimates can change materially from period to period based on many factors, including those described in the preceding paragraph. Accordingly, if conditions change in the future, we may record impairment losses relative to our seismic data library, which could be material to any particular reporting period.

Goodwill

Goodwill is not amortized to earnings but is assessed, at least annually, for impairment at the reporting unit level. We conduct an annual assessment of the recoverability of goodwill as of October 1 of each year. We first assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. If the qualitative assessment indicates that it is more likely than not that the fair value of the reporting unit is less than its carrying amount or we elect not to perform a qualitative assessment, the quantitative assessment or two-step goodwill test is performed. The two-step goodwill impairment test is also performed whenever events or changes in circumstances indicate that the carrying value may not be recoverable.

Use of Estimates and Assumptions

In preparing our consolidated financial statements, a number of estimates and assumptions are made by management that affect the accounting for and recognition of assets, liabilities, revenues and expenses. These estimates and assumptions must be made because certain information that is used in the preparation of our consolidated financial statements is dependent on future events, cannot be calculated with a high degree of precision from data available or is not otherwise capable of being readily calculated based on generally accepted methodologies. In some cases, these estimates are particularly difficult to determine and we must exercise significant judgment.

The most difficult, subjective and complex estimates and assumptions that deal with the greatest amount of uncertainty are related to our accounting for our seismic data library, goodwill and realizability of our deferred tax assets.

Accounting for our seismic data library requires us to make significant subjective estimates and assumptions relative to future sales and cash flows from such library. These cash flows impact amortization rates, as well as potential impairment charges. Any changes in these estimates or underlying assumptions will impact our income from operations prospectively from the date changes are made. To the extent that such estimates, or the assumptions used to make those estimates, prove to be significantly different than actual results, the carrying value of the seismic data library may be subject to higher prospective amortization rates, additional straight-line amortization or impairment losses.

We apply a minimum income forecast amortization rate of 70% and the effect of decreasing future sales by either 10% or 20%, with all other factors remaining constant, would not increase amortization rates from 70% as of January 1, 2017.

In a portion of our seismic data library activities, we engage in certain non-monetary exchanges and record a data library asset for the seismic data received and recognize revenue on the transaction in accordance with our policies on revenue recognition. These transactions are valued at the fair value of the data received by us or licenses or services granted by us, whichever is more readily determinable. Our estimate of the value of these transactions is highly subjective and based, in large part, on data sales transactions between us and a limited number of customers over a limited time period.

If it is necessary to perform an analysis to determine if our goodwill is impaired, the two-step impairment test is performed to identify potential goodwill impairment and measure the amount of a goodwill impairment loss to be recognized. The impairment test involves a comparison of the fair value of a reporting unit with its carrying amount, including goodwill to identify if a goodwill impairment exists. For our estimates of the fair value of goodwill, we prepare discounted cash flow analysis, which requires significant judgments and estimates about our future performance. If these projected cash flows change materially, we may be required to record impairment losses relative to goodwill.

In evaluating our ability to recover our deferred tax assets, we consider all available positive and negative evidence, including scheduled reversals of deferred tax liabilities, projected future taxable income, tax-planning strategies and results of recent operations. The assumptions about future taxable income require significant judgment and are consistent with the plans and estimates management is using to manage the underlying business. If the projected future taxable income changes materially, we may be required to reassess the amount of valuation allowance recorded against our deferred tax assets.

Actual results could differ materially from the estimates and assumptions that we use in the preparation of our financial statements. To the extent management’s estimates and assumptions change in the future, the effect on our reported results could be significant to any particular reporting period.

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Results of Operations

Revenue

The following table summarizes the components of our revenue for the years ended December 31, 2016, 2015 and 2014 (in thousands):

	Year Ended December 31,		
	2016	2015	2014
Acquisition underwriting revenue:			
Cash underwriting	$21,329	$42,566	$59,922
Underwriting from non-monetary exchanges	129	168	38
Total acquisition underwriting revenue	21,458	42,734	59,960
Resale licensing revenue:			
Cash resales	59,404	44,350	123,530
Non-monetary exchanges	1,840	9,300	741
Revenue recognition adjustments	9,752	1,554	9,806
Total resale licensing revenue	70,996	55,204	134,077
Total seismic revenue	92,454	97,938	194,037
Solutions and other	2,092	2,314	4,000
Total revenue	$94,546	$100,252	$198,037

Total revenue for the year ended December 31, 2016 was $94.5 million compared to $100.3 million for the year ended December 31, 2015. The decrease in total revenue was mainly due to a reduction in acquisition underwriting revenue partially offset by an increase in resale licensing revenue. Acquisition underwriting revenue was $21.5 million in 2016 compared to $42.7 million in 2015. The decrease in acquisition underwriting revenue was primarily attributable to a planned reduction in new data acquisition projects as a result of the prolonged downturn in the energy industry. Our new data acquisition activity in 2016 primarily occurred in the Louisiana Cotton Valley and Permian unconventional plays in the U.S. Total resale licensing revenue was $71.0 million in 2016 compared to $55.2 million in 2015. Cash resales increased from $44.4 million in 2015 to $59.4 million in 2016. Cash resales showed year over year improvement in the last three quarters of 2016, with particular strength in the fourth quarter, as client spending increased as crude oil prices recovered from the lows experienced in the first quarter of 2016. Non-monetary exchanges fluctuate year to year depending upon data available for trade. We had one large non-monetary exchange in 2015 causing the significant decrease from 2015 to 2016. Revenue recognition adjustments are non-cash adjustments to revenue and reflect the net amount of (i) revenue deferred as a result of all of the revenue recognition criteria not being met and (ii) the subsequent revenue recognition once the criteria are met. The increase of $8.2 million in revenue recognition adjustments from 2015 to 2016 was primarily due to lower deferrals associated with new licensing contracts and an increase in revenue recognized on previously deferred direct licensing contracts, slightly offset by a decrease in selections of data from library card contracts. Solutions and other revenue was $2.1 million in 2016 compared to $2.3 million in 2015.

Total revenue for the year ended December 31, 2015 was $100.3 million compared to $198.0 million for the year ended December 31, 2014. The decrease in total revenue was mainly due to a reduction in resale licensing revenue. Acquisition underwriting revenue was $42.7 million in 2015 compared to $60.0 million in 2014. The decrease in acquisition underwriting revenue was primarily attributable to a reduction in activity in the U.S. and Canada due to a decline in capital spending by E&P companies as a result of the prolonged and deep decline in crude oil prices. Our new data acquisition activity in 2015 primarily occurred in the Eagle Ford/Woodbine and Permian unconventional plays in the U.S. and the Montney and Duvernay unconventional plays in Canada. Total resale licensing revenue was $55.2 million in 2015 compared to $134.1 million in 2014. Cash resales were $44.4 million in 2015 compared to $123.5 million in 2014 reflecting lower activity levels by our clients as a result of less drilling and reduced capital expenditures stemming from the drop in crude oil prices beginning in late 2014 and continuing throughout 2015. Non-monetary exchanges fluctuate year to year depending upon data available for trade. We had one large non-monetary exchange in 2015 causing the significant increase from 2014. The decrease of $8.3 million in revenue recognition adjustments from 2014 to 2015 was primarily due to a decrease in selections of data from library card contracts and a decrease in revenue recognized on previously deferred direct licensing contracts, partially offset by lower deferrals associated with new licensing contracts. Solutions and other revenue was $2.3 million in 2015 compared to $4.0 million in 2014. The $1.7 million decrease was due to the lower level of total seismic revenue.

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At December 31, 2016, we had a deferred revenue balance of $15.9 million compared to the December 31, 2015 balance of $25.9 million. The deferred revenue balance was related to (i) data licensing contracts on which selection of specific data had not yet occurred, (ii) deferred revenue on data acquisition projects and (iii) contracts in which the data products are not yet available or the revenue recognition criteria has not yet been met. The deferred revenue will be recognized when selection of specific data is made by the customer, upon expiration of the data selection period specified in the data licensing contracts, as work progresses on the data acquisition contracts, as the data products become available for delivery or as all of the revenue recognition criteria are met. Deferred revenue will be recognized no later than the following, based on the expiration of the selection period or our estimate of progress on acquisition projects and the availability of data products, although some revenue may be recognized earlier (in thousands):

2017	$11,141
2018	3,584
2019 and thereafter	1,179

Depreciation and Amortization

The table below sets forth the components of depreciation and amortization and presents seismic data amortization as a percentage of total seismic revenue for the years ended December 31, 2016, 2015 and 2014 (dollars in thousands):

	Year Ended December 31,			Percentage of Revenue		
	2016	2015	2014	2016	2015	2014
Amortization of seismic data:						
Income forecast	$28,746	$44,976	$92,819	31%	46%	48%
Straight-line	41,441	30,916	22,740	45%	32%	12%
Total amortization of seismic data	70,187	75,892	115,559	76%	78%	60%
Depreciation of property and equipment	735	850	975			
Amortization of acquired intangibles	4,156	4,181	4,489			
Total	$75,078	$80,923	$121,023			

Total seismic data library amortization amounted to $70.2 million, $75.9 million and $115.6 million in 2016, 2015 and 2014, respectively. The amount of seismic data library amortization fluctuates based on the level and location of specific seismic surveys licensed (including licensing resulting from new data acquisition) and selected by our customers during any period as well as the amount of straight-line amortization required under our accounting policy. The percentage of income forecast amortization to total seismic revenue was 31% for the year ended December 31, 2016, 46% for the year ended December 31, 2015, and 48% for the year ended December 31, 2014. In all three years, we recognized resale revenue from data whose costs were fully amortized. In 2016, 72% of resales did not require amortization, as compared to 60% in 2015 and 46% in 2014. Additionally, all acquisition revenue attracts amortization; thus, the decreasing level of acquisition revenue between periods impacted the overall percentage of income forecast amortization. Straight-line amortization represents the expense required under our accounting policy to ensure our data value is fully amortized within four years of when the data is completed and becomes available for licensing. The amount of straight-line amortization will vary between periods due to the distribution of revenue among the various surveys.

For each of the years ended December 31, 2016, 2015 and 2014, the rate utilized under the income forecast method was 70% for all components. The rate of amortization with respect to each component is decreased or increased if our estimate of future cash sales from such component is materially increased or decreased, subject to a minimum amortization rate of 70%. Additionally, certain seismic surveys have been fully amortized; consequently, no amortization expense is required on revenue recorded for these seismic surveys. As of January 1, 2017, the amortization rate to be utilized under the income forecast method is 70% for all components.

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Selling, General and Administrative Expenses

Selling, general and administrative ("SG&A") expenses were $24.1 million in 2016, $22.2 million in 2015 and $29.8 million in 2014. SG&A expenses are made up of the following cash and non-cash expenses (in thousands):

	Year Ended December 31,		
	2016	2015	2014
Cash SG&A expenses	$24,042	$21,856	$29,263
Non-cash compensation expense	77	328	536
Total	$24,119	$22,184	$29,799

Cash SG&A expenses increased $2.2 million from 2015 to 2016 primarily due to a $0.9 million increase in routine overhead costs and a $1.3 million increase in non-routine costs. The increase in routine overhead costs mainly consisted of an increase in variable compensation, consisting of commissions and annual incentive compensation, of $3.9 million and an increase of $0.7 million in professional fees partially offset by savings of $2.8 million in salaries and benefits from headcount reductions and $0.9 million in various other cost savings. The majority of the increase in variable compensation in 2016 compared to 2015 was due to annual incentive compensation being earned in 2016 as our Cash EBITDA results exceeded the target goals established for 2016; no annual incentive compensation was recorded in 2015. The increase in professional fees mainly resulted from legal fees incurred in successfully protecting our contract and intellectual property rights in connection with a number of bankruptcy proceedings filed by our clients. Our savings in salaries and benefits resulted from an approximate 40% reduction in headcount since the beginning of 2015 through attrition and layoffs. The overall increase in non-routine costs was primarily due to an increase in termination benefits related to layoffs in 2016.

The decrease in cash SG&A expenses of $7.4 million from 2014 to 2015 was primarily due to a decrease of $4.9 million in variable expenses, consisting of commissions and annual incentive compensation, resulting from the decrease in revenue and Cash EBITDA. The additional reduction in SG&A expenses of $2.5 million was primarily due to a targeted reduction in overall expenses including headcount reductions during 2015 through attrition and our October 2015 layoff, reductions in travel and entertainment and various other planned cost savings.

Other Income (Expense)

During the years ended December 31, 2016, 2015 and 2014, we reported foreign currency transaction gains (losses) on U.S. denominated transactions of our Canadian subsidiaries totaling $0.1 million, $(1.7) million and $(2.0) million, respectively.

We recorded $1.7 million in other income during the year ended December 31, 2016 primarily related to gains associated with the extinguishment of liabilities. The gains were the result of the legal cancellation or expiration of our existing liabilities related to contingent payments on certain seismic data assets.

Income Tax Expense (Benefit)

Income tax expense (benefit) was $(3.4) million, $79.9 million and $10.3 million for the years ended December 31, 2016, 2015 and 2014, respectively, and was comprised of the following (in thousands):

	Year Ended December 31,		
	2016	2015	2014
Change in U.S. federal and state valuation allowance on deferred tax assets	$8,617	$88,737	$—
U.S federal taxes	(8,582)	(6,944)	10,575
U.S. state taxes	8	40	1,212
Canadian federal and provincial taxes	(803)[1]	(2,004)	(1,680)
Canadian research and development tax credits	—	(346)	—
Mexico federal taxes	117	—	—
Change in unrecognized tax positions	(2,780)	422	186
Other	27	—	—
Total tax expense (benefit)	$(3,396)	$79,905	$10,293

(1)2016 amount is net of change in valuation allowance of $24.

The income tax benefit of $3.4 million in 2016 was mainly comprised of a $2.8 million benefit related to uncertain tax positions resulting from settlement of our outstanding appeal with Canada Revenue Agency, remeasurement of our remaining

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uncertain tax positions and lapse of statute of limitations on certain positions during the year. Additional tax benefits of $0.8 million related to our Canadian operations were offset slightly by $0.1 million of tax expense related to our Mexican operations. The federal tax benefit of $8.6 million resulting from our U.S. operations was offset by a valuation allowance because it was more likely than not that the deferred tax asset would not be realized.

At December 31, 2015, we recorded a valuation allowance of $88.7 million against all of our U.S. federal deferred tax assets and the majority of our state net deferred tax assets based on management's assessment that it is more likely than not that our deferred tax assets will not be realized. The reduction in U.S. federal and state tax expense from 2014 to 2015 was primarily due to the decrease in our U.S. taxable income resulting from lower revenues due to reductions in E&P spending in light of the low crude oil price environment. Canada's tax benefit of $2.0 million in 2015 and $1.7 million in 2014 resulted from losses reported in our Canadian operations.

Net Income (Loss)

Net loss was $24.4 million in 2016 compared to $110.0 million in 2015. The $85.6 million decrease in loss was primarily attributable to $88.7 million in tax expense recorded in 2015 in order to provide a valuation allowance on our U.S. federal and state deferred tax assets.

Net income (loss) was $(110.0) million in 2015 compared to $9.7 million in 2014. The $119.7 million decrease was primarily due to $88.7 million in tax expense recorded in 2015 in order to provide a valuation allowance on our U.S. federal and state deferred tax assets. Additionally, 2015 included a reduction in revenues from 2014, partially offset by lower amortization of seismic data and a decrease in SG&A expenses.

Liquidity and Capital Resources

As of December 31, 2016, we had $56.0 million in consolidated cash, cash equivalents and short-term investments, including $0.5 million of restricted cash. Our Canadian subsidiary regularly holds cash that is used to reinvest in its operations. If we decide at a later date to repatriate those funds to the U.S., we may be required to provide taxes on certain of those funds based on applicable U.S. tax rates net of foreign taxes. Cash held by our Canadian subsidiary fluctuates throughout the year and at December 31, 2016, was approximately $8.0 million.

Our primary sources of liquidity are cash on hand and cash generated from operations. Historically, our liquidity sources also included available borrowings under our credit facility; however, the credit facility expired on its own terms in May 2016 and management made a decision not to renew or extend this facility. A summary of our 9½% Senior Notes is included below; for additional information regarding the 9½% Senior Notes, See "Note E - Debt" in the Notes to Consolidated Financial Statements herein.

9½% Senior Unsecured Notes: On March 20, 2013, we issued in a private placement $250.0 million aggregate principal amount of our 9½% Senior Notes. Interest is payable in cash, semi-annually on April 15 and October 15 of each year. The notes mature on April 15, 2019. To the best of our knowledge, we are in compliance with all covenants contained in the indenture governing our 9½% Senior Notes at December 31, 2016.

We may from time to time, as part of various financing and investing strategies, purchase our outstanding indebtedness. These purchases, if any, could have a material positive or negative impact on our liquidity available to repay outstanding debt obligations or on our consolidated results of operations.

Contractual Obligations: The following table summarizes our future contractual obligations as of December 31, 2016 (in thousands):

		Payments due by period			
Contractual cash obligations	Total	2017	2018-2020	2021-2022	2023 and thereafter
Debt obligations [1] [2]	$309,375	$23,750	$285,625	$ —	$ —
Capital lease obligations [2]	1,786	326	1,011	449	—
Operating lease obligations	2,368	634	1,372	362	—
Total contractual cash obligations	$313,529	$24,710	$288,008	$ 811	$ —

(1)Debt obligations include the face amount of our 9½% Senior Notes totaling $250.0 million.

(2)Amounts include interest related to debt and capital lease obligations.

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Cash Flows from Operating Activities: Cash flows provided by operating activities were $30.5 million, $72.6 million and $124.3 million for the years ended December 31, 2016, 2015 and 2014, respectively. Operating cash flows for 2016 decreased from 2015 primarily due to 2015 including significant collections from fourth quarter 2014 cash resale activity and lower acquisition underwriting revenue in 2016. Operating cash flows for 2015 decreased from 2014 primarily due to the reduced level of cash resales in 2015 and also due to lower acquisition underwriting revenue

Cash Flows from Investing Activities: Cash flows used in investing activities were $27.0 million, $77.7 million and $95.7 million for the years ended December 31, 2016, 2015 and 2014, respectively. Cash expenditures for seismic data were $26.7 million, $77.3 million and $93.7 million for the years ended December 31, 2016, 2015 and 2014, respectively. The decrease in cash invested in seismic data for 2016 compared to 2015 was primarily due to a planned reduction in our capital expenditures as a result of the prolonged downturn in the industry environment. The decrease in cash invested in seismic data for 2015 compared to 2014 was primarily due to decreased data acquisition activity in the U.S. and Canada.

Cash Flows from Financing Activities: Cash flows used in financing activities were $0.2 million for each of the years ended December 31, 2016, 2015 and 2014, respectively.

Anticipated Liquidity: Our ability to cover our operating and capital expenses, make required debt service payments on our 9½% Senior Notes, incur additional indebtedness and comply with our various debt covenants will depend primarily on our ability to generate substantial operating cash flows. Over the next 12 months, we expect to obtain the funds necessary to pay our operating, capital and other expenses, as well as interest on our 9½% Senior Notes and principal and interest on our other indebtedness, from our operating cash flows and cash and cash equivalents on hand. Our ability to satisfy our payment obligations depends substantially on our future operating and financial performance, which necessarily will be affected by, and subject to, industry, market, economic and other factors. To the extent our operating cash flows and cash on hand are not sufficient to cover our anticipated expenditures, we could seek to obtain additional financing. However, there can be no assurance that we would be able to obtain any such financing on satisfactory terms or at all. If necessary, we could choose to further reduce our spending on capital projects and operating expenses to ensure we operate within the cash flow generated from our operations. We will not be able to predict or control many of these factors, such as economic conditions in the markets where we operate and competitive pressures.

For a discussion of a number of factors that may impact our liquidity and the sufficiency of our capital resources, see “Overview” and “Item 1A. Risk Factors” above.

Deferred Taxes

As of December 31, 2016, we had a net deferred tax liability of $2.2 million attributable to our Canadian operations. In the United States, we had a federal deferred tax asset of $94.1 million, which was fully offset by a valuation allowance, and a state deferred tax asset of $1.3 million of which $1.2 million was offset by a valuation allowance. We continue to provide a full valuation allowance against our U.S. federal tax assets and the majority of our state deferred tax assets as we believe it is more likely than not that all or some portion of these deferred tax assets will not be realized. The most significant piece of negative evidence in making this assessment was the pretax book losses for the years ended December 31, 2015 and 2016 which resulted in a cumulative pretax book loss as of December 31, 2016. Available positive evidence considered did not outweigh this negative evidence as of December 31, 2016. The remaining state deferred tax asset of $0.1 million was recognized as it is more likely than not that the state deferred tax asset will be realized. With regard to our Mexican operations, we had a deferred tax asset of $0.2 million that was recognized as of December 31, 2016 as our Mexican operations have generated cumulative pretax book income as of December 31, 2016; therefore, it is more likely than not that the deferred tax asset will be realized.

Off-Balance Sheet Transactions

Other than operating leases, we do not maintain any off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have a material current or future effect on our financial condition, changes in financial condition, revenue or expense, results of operations, liquidity, capital expenditures or capital resources.

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Capital Expenditures

During 2016, capital expenditures for seismic data and other property and equipment amounted to $23.6 million on a gross basis and $(0.4) million on a net cash basis. Our 2016 capital expenditures are comprised of the following (in thousands):

	Year Ended December 31, 2016
New data acquisition	$ 19,029
Cash purchases and data processing	1,615
Non-monetary exchanges	2,640
Property and equipment	304
Total capital expenditures	23,588
Less: Non-monetary exchanges	(2,640)
Changes in working capital	6,018
Cash investment per statement of cash flows	$ 26,966

Net cash capital expenditures represent total capital expenditures less cash underwriting revenue from our clients and non-cash additions to the seismic data library. We believe this measure is important as it reflects the amount of capital expenditures funded from our operating cash flow. The following table shows how our net cash capital expenditures (a non-GAAP financial measure) are derived from total capital expenditures, the most directly comparable GAAP financial measure (in thousands):

	Year Ended December 31, 2016
Total capital expenditures	$ 23,588
Less: Non-monetary exchanges	(2,640)
Cash underwriting	(21,329)
Net cash capital expenditures	$ (381)

Net cash capital expenditures for the year ended December 31, 2016, reflected acquisition underwriting revenue in excess of gross cash capital costs. Gross cash capital costs in 2016 included a revision to the previous estimated costs related to one of our new data acquisition surveys resulting in a reduction of the gross costs of approximately $2.5 million.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2014-09, “Revenue from Contracts with Customers (Topic 606)”. The objective of the ASU is to establish a single comprehensive model of accounting for revenue arising from contracts with customers and will supersede most of the existing revenue recognition guidance, including industry-specific guidance. The core principle of the guidance is that an entity recognizes revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This ASU also significantly expands disclosure requirements concerning revenues for most entities. In August 2015, the FASB issued ASU No. 2015-14, “Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date” which deferred the effective date of ASU 2014-09 by one year. In March 2016, the FASB issued ASU No. 2016-08, “Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net)”, amending the principal-versus-agent implementation guidance set forth in ASU 2014-09. Among other things, ASU 2016-08 clarifies that an entity should evaluate whether it is the principal or the agent for each specified good or service promised in a contract with a customer. In April 2016, the FASB issued ASU No. 2016-10, “Revenue from

Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing", which amends certain aspects of the guidance related to identifying performance obligations and licensing implementation. In May 2016, the FASB issued ASU No. 2016-12, "Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients" to address certain issues in the guidance on assessing collectibility, presentation of sales taxes, noncash consideration, and completed contracts and contract modifications at transition. The Company is required to adopt the guidance set forth by these ASUs on January 1, 2018. Entities have the option of using either a full retrospective or modified retrospective approach to adopt the new guidance. We anticipate utilizing the modified retrospective approach when adopting the new revenue recognition guidance effective January 1, 2018 which will result in the application of the new guidance retrospectively with the cumulative effect of adoption recognized at January 1, 2018, the date of initial application. We are in the process of reviewing our customer contracts and comparing our current revenue recognition policies to the provisions of the new standard for each of our revenue categories. While we have not identified any material differences in the amount and timing of revenue recognition for the categories we have reviewed to date, our evaluation is not complete and we have not

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concluded on the overall impacts of adopting the new guidance. The FASB has issued, and may issue in the future, interpretive guidance which may cause our evaluation to change. We believe we are following an appropriate timeline to allow for proper recognition, presentation and disclosure upon adoption.

In February 2016, the FASB issued ASU No. 2016-02, “Leases (Topic 842)” with the objective of increasing transparency and comparability among organizations by requiring lessees to recognize assets and liabilities on the balance sheet for the present value of the rights and obligations created by all leases with terms of more than 12 months. The ASU will also require disclosures designed to give financial statement users information on the amount, timing and uncertainty of cash flows arising from leases. The amendments in this ASU are to be applied using a modified retrospective approach and will be effective for us as of January 1, 2019, but early adoption is permitted. We are currently evaluating the impact of adopting this new standard on our consolidated financial statements as of January 1, 2019 and believe that the most significant change will be to our balance sheet as our asset and liability balances will increase for operating leases that are currently off-balance sheet.

In March 2016, the FASB issued ASU No. 2016-09, “Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting.” The amendments in this ASU simplify several aspects of the accounting for employee share-based payment transactions, including the accounting for income taxes, forfeitures and statutory tax withholding requirements, as well as classification in the statement of cash flows. This guidance is effective for us on January 1, 2017, with early adoption permitted. Adoption of ASU 2016-09 will not have a material effect on our consolidated financial statements.

In January 2017, the FASB issued ASU No. 2017-04, “Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment” in order to simplify the measurement of goodwill impairment by eliminating Step 2 from the goodwill impairment test. Currently, Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit’s goodwill with the carrying amount of that goodwill. In computing the implied fair value of goodwill under Step 2, an entity had to perform procedures to determine the fair value at the impairment testing date of its assets and liabilities following the same procedure that would be required for purchase price allocation in a business combination. Under the amendments in this ASU, a goodwill impairment loss will be measured using the difference between the carrying amount and the fair value of the reporting unit limited to the total carrying amount of that reporting unit’s goodwill. The guidance in this ASU also eliminates the requirements for any reporting unit with a zero or negative carrying amount to perform a qualitative assessment and, if it fails that qualitative test, to perform Step 2 of the goodwill impairment test. However, entities must disclose the amount of goodwill allocated to each reporting unit with a zero or negative carrying amount. The amendments in this ASU are to be applied on a prospective basis and will be effective for us as of January 1, 2020, but early adoption is permitted for any impairment tests performed after January 1, 2017. We are