VAALCO ENERGY INC /DE/
Form 10-K
March 07, 2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2017

OR

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

For the transition period from to

Commission file number: 1-32167

VAALCO Energy, Inc.

(Exact name of registrant as specified on its charter)

Delaware	76-0274813
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

9800 Richmond Avenue

Suite 700

Houston, Texas 77042

(Address of principal executive offices) (Zip Code)

(Registrant's telephone number, including area code): (713) 623-0801

Securities registered under Section 12(b) of the Exchange Act:

Title of each class	Name of exchange on which registered
Common Stock, $.10 par value	New York Stock Exchange

Securities registered under Section 12(g) of the Exchange Act: None

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

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

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

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

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

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

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

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

The aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates, as of June 30, 2017 was approximately $54.2 million based on a closing price of $0.94 on June 30, 2017.

As of February 28, 2018, there were outstanding 58,862,876 shares of common stock, $0.10 par value per share, of the registrant.

Documents incorporated by reference: Definitive proxy statement of VAALCO Energy, Inc. relating to the Annual Meeting of Stockholders to be filed within 120 days after the end of the fiscal year covered by this Form 10-K, which is incorporated into Part III of this Form 10-K.

VAALCO ENERGY, INC.

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Glossary of Terms

Terms used to describe quantities of oil and natural gas

- Bbl — One stock tank barrel, or 42 United States ("U.S.") gallons liquid volume, of crude oil or other liquid hydrocarbons.
- BOE — One barrel of oil equivalent, converting natural gas to oil at the ratio of 6 Mcf of natural gas to 1 Bbl of oil. The ratio of six Mcf of natural gas to one Bbl of oil or natural gas liquids is commonly used in the oil and natural gas business and represents the approximate energy equivalency of natural gas to oil or liquids, and does not represent the sales price equivalency of natural gas to oil or liquids.
- BOPD — One barrel of oil per day.
- MBbl — One thousand Bbls.
- MBOE— One thousand barrels of oil equivalent.
- Mcf — One thousand cubic feet of natural gas.
- MMbtu — One million British thermal units, a measure commonly used for natural gas pricing.
- MMcf — One million cubic feet of natural gas.
- MMBbl — One million Bbls.

Terms used to describe legal ownership of oil and natural gas properties, and other terms applicable to our operations

- Carried interest — Working interest owners (defined below) whose share of costs are paid by the non-carried working interest owners and whose share of revenues are paid to non-carried working interest owners until such owners costs have been repaid.
- Consortium –A consortium of four companies granted rights and obligations in the Etame Marin block offshore Gabon under a Production Sharing Contract with the Republic of Gabon.
- PSC — A production sharing contract; Etame PSC is the Etame Production Sharing Contract, as amended, and as it may be further amended, that we have entered into with the Republic of Gabon, related to the Etame Marin block located offshore Gabon.
- FPSO — A floating, production, storage and offloading vessel.
- Participating interest — Working interest (as defined below) attributable to a non-carried interest owner adjusted to include its relative share of the benefits and obligations attributable to carried working interest owners.
- Royalty interest — A real property interest entitling the owner to receive a specified portion of the gross proceeds of the sale of oil and natural gas production or, if the conveyance creating the interest provides, a specific portion of oil and natural gas produced, without any deduction for the costs to explore for, develop or produce the oil and natural gas.
- Working interest — A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.

Terms used to describe interests in wells and acreage

- Gross oil and natural gas wells or acres — Gross wells or gross acres represent the total number of wells or acres in which a working interest is owned, before consideration of the ownership percentage.
- Net oil and natural gas wells or acres — Determined by multiplying "gross" wells or acres by the owned working interest.

Terms used to classify reserve quantities

- Developed oil and natural gas reserves — Developed oil and natural gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

- Proved oil and natural gas reserves — Proved oil and natural gas reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible (from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations) prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

- Reserves — Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market, and all permits and financing required to implement the project.
- Undeveloped oil and natural gas reserves — Undeveloped oil and natural gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

· Unproved properties — Properties with no proved reserves.

Terms used to assign a present value to reserves

· Standardized measure — The standardized measure of discounted future net cash flows ("standardized measure") is the present value, discounted at an annual rate of 10%, of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the Securities and Exchange Commission

("SEC"), using the 12-month unweighted average of first-day-of-the-month Brent prices adjusted for historical marketing differentials, (the "12-month average"), without giving effect to non–property related expenses such as certain general and administrative expenses, debt service, derivatives or to depreciation, depletion and amortization.

Terms used to describe seismic operations

· Seismic data — Oil and natural gas companies use seismic data as their principal source of information to locate oil and natural gas deposits, both to aid in exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones which digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.
· 2-D seismic data. — 2-D seismic survey data has been the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data.
· 3-D seismic data — 3-D seismic data is collected using a grid of energy sources, which are generally spread over several miles. A 3-D survey produces a three dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is a more reliable indicator of potential oil and natural gas reservoirs in the area evaluated.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, (the "Exchange Act") which are intended to be covered by the safe harbors created by those laws. We have based these forward-looking statements on our current expectations and projections about future events. These forward-looking statements include information about possible or assumed future results of our operations. All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect or anticipate may occur in the future, including without limitation, statements regarding our financial position, operating performance and results, reserve quantities and net present values, market prices, business strategy, derivative activities, the amount and nature of capital expenditures and plans and objectives of management for future operations are forward-looking statements. When we use words such as "anticipate," "believe," "estimate," "expect," "intend," "forecast," "outlook," "aim,", "target", "wi "should," "may," "likely," "plan," "probably" or similar expressions, we are making forward-looking statements. Many risks a uncertainties that could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include, but are not limited to:

· volatility of, and declines and weaknesses in oil and natural gas prices;
· the discovery, acquisition, development and replacement of oil and natural gas reserves;
· our ability to maintain sufficient liquidity in order to fully implement our business plan;
· our ability to generate cash flows that, along with our cash on hand, will be sufficient to support our operations and cash requirements;
· future capital requirements and our ability to attract capital;
· our ability to replace our loan facility under our agreement with the International Finance Corporation ("IFC credit facility"), as amended ("Amended Term Loan Agreement") with another credit facility to help fund our future capital requirements;
· our ability to resolve satisfactorily matters related to our exit from Angola, including our obligations to pay the amount, as it is ultimately determined, of our liabilities to Sonangol E.P. with respect to our production sharing contract;
· our ability to extend the license period for the Etame block offshore Gabon;

- our ability to meet the financial covenants of our Amended Term Loan Agreement;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;
- the impact of competition;
- weather conditions;
- the uncertainty of estimates of oil and natural gas reserves;
- currency exchange rates;

- unanticipated issues and liabilities arising from non-compliance with environmental regulations;
- the ultimate resolution of our abandonment funding obligations with the government of Gabon and the audit of our operations in Gabon currently being conducted by the government of Gabon;
- our ability to meet the continued listing standards of the New York Stock Exchange (“NYSE”), or to cure any deficiency in meeting the listing standards;
- the timing and effectiveness of our remediating the significant deficiencies and material weaknesses in our internal control over financial reporting;
- the availability and cost of seismic, drilling and other equipment;
- difficulties encountered in measuring, transporting and delivering oil to commercial markets;
- timing and amount of future production of oil and natural gas;
- hedging decisions, including whether or not to enter into derivative financial instruments;
- our ability to effectively integrate assets and properties that we acquire into our operations;
- our ability to pay the expenditures required in order to develop certain of our properties offshore Equatorial Guinea;
- general economic conditions, including any future economic downturn, disruption in financial markets and the availability of credit;
- changes in customer demand and producers’ supply;
- actions by the governments of and events occurring in the countries in which we operate;
- actions by our venture partners;
- compliance with, or the effect of changes in, governmental regulations regarding our exploration, production, and well completion operations including those related to climate change;
- the outcome of any governmental audit; and
- actions of operators of our oil and natural gas properties.

The information contained in this report, including the information set forth under the heading “Item 1A. Risk Factors,” identifies additional factors that could cause our results or performance to differ materially from those we express in forward-looking statements. Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of these assumptions and therefore also the forward-looking statements based on these assumptions, could themselves prove to be inaccurate. In light of the significant uncertainties inherent in the forward-looking statements which are included in this report, our inclusion of this information is not a representation by us or any other person that our objectives and plans will be achieved. When you consider our forward-looking statements, you should keep in mind these risk factors and the other cautionary statements in this report.

Our forward-looking statements speak only as of the date made, and reflect our best judgment about future events and trends based on the information currently available to us. Our results of operations can be affected by inaccurate assumptions we make or by risks and uncertainties known or unknown to us. Therefore, we cannot guarantee the accuracy of the forward-looking statements. Actual events and results of operations may vary materially from our current expectations and assumptions. Our forward-looking statements are expressly qualified in their entirety by this “Special Note Regarding Forward-Looking Statements,” which constitute cautionary statements.

PART I

Item 1. Business

BACKGROUND

VAALCO Energy, Inc. is a Delaware corporation, incorporated in 1985 and headquartered at 9800 Richmond Avenue, Suite 700, Houston, Texas 77042. Our telephone number is (713) 623-0801 and our website address is www.vaalco.com. As used in this Annual Report on Form 10-K, the terms, “we”, “us”, “our”, and “VAALCO” refer to VAALCO Energy, Inc. and its consolidated subsidiaries, unless the context otherwise requires.

We are a Houston, Texas based independent energy company engaged in the acquisition, exploration, development and production of crude oil. Our primary source of revenue has been from our Etame Production Sharing Contract (“Etame PSC”) related to the Etame Marin block located offshore the Republic of Gabon (“Gabon”) in West Africa. We also currently own interests in an undeveloped block offshore Equatorial Guinea, West Africa. As discussed further in Note 5 to the audited consolidated financial statements included in Part III, Item 8 – “Consolidated Financial Statements and Supplementary Data”(“Financial Statements”), we have discontinued operations associated with our activities in Angola, West Africa.

Our consolidated subsidiaries are VAALCO Gabon (Etame), Inc., VAALCO Production (Gabon), Inc., VAALCO Gabon S.A., VAALCO Angola (Kwanza), Inc., VAALCO UK (North Sea), Ltd., VAALCO International, Inc., VAALCO Energy (EG), Inc., VAALCO Energy Mauritius (EG) Limited and VAALCO Energy (USA), Inc.

STRATEGY

Our strategy is to utilize our technical expertise and operational infrastructure, with a focus on extending our existing license in Gabon, further developing our Gabon resources and expanding into new development opportunities in West Africa. A significant component of our results of operations is dependent upon the difference between prices received for our offshore Gabon oil production and the costs to find and produce such oil. Oil and natural gas prices have been volatile and subject to fluctuations based on a number of factors beyond our control. Beginning in the third quarter of 2014, the global prices for oil and natural gas began a dramatic decline, which continued through 2015 and into 2016. During this period, we scaled back our global operations, divested non-core assets, amended our credit agreement and focused on reducing costs and maximizing our cash flows. Crude prices improved during 2017 from \$55 per Bbl at the end of 2016 to \$67 per Bbl at the end of 2017. We have conducted no drilling activities in 2016 and 2017, but we may drill two or three development wells in 2018, subject to partner and governmental approval.

At December 31, 2017, we had estimated net proved developed reserves of 3.0 million barrels of oil equivalent. For 2017, our reserves replacement amount was equal to 127% of our 2017 Gabon production, as reflected in the reserve report issued by our independent petroleum engineering firm, Netherland, Sewell & Associates, Inc. (NSAI"). We added 1.3 MMBOE of reserves through reservoir performance additions and 0.6 MMBOE through positive pricing revisions. The increase in the average of the first-day-of-the-month prices adjusted for quality, transportation fees and market differentials required by SEC rules to determine reserves, was from \$40.35 for the 2016 year-end report to \$53.49 for the 2017 year-end report.

Assuming oil and natural gas prices continue at current levels (and holding other variables constant), we believe that through March 31, 2019 we will be able generate cash flows sufficient to cover our operating expenses. However, an unfavorable resolution of our current obligations or a return to the levels of depressed oil and natural gas prices seen in the first quarter of 2016 would have a material adverse effect on our liquidity, financial condition and results of operations. To fund any potential growth opportunities going forward, we are considering multiple alternatives, including, but not limited to, additional debt or equity financing through traditional sources or strategic partnerships (see "— Strategic Alternatives and Operating Strategies" below). There can be no guarantee of future capital acquisition or fundraising success. We currently have no availability for additional borrowings under our Amended Term Loan Agreement. Our current cash position and our ability to access additional capital may limit our available opportunities.

We believe that improved crude oil prices as well as increases in our reserves have favorable implications for our company's cash flows, potential access to capital, liquidity and financial condition and we may incur capital expenditures in 2018 for development, which may require additional capital.

Strategic Alternatives and Operating Strategies. Our Board of Directors has appointed a strategic committee to oversee the evaluation of our strategic alternatives including those discussed below. We can give no assurances that any of these strategic alternatives can be completed, and if so, on reasonable terms that are acceptable to us.

Our strategic growth alternatives are as follows:

- Identify viable acquisition targets and/or merger opportunities;
- Consider joint ventures that allow us to leverage our operating capabilities and proven West Africa experience;
- Exit non-core exploration assets to focus on development opportunities; and

- Obtain external funding necessary for growth opportunities and maintaining our liquidity.

Our operating strategies for 2018 are financially driven and are as follows:

- Maximize our cash flow;
- Manage our capital expenditures and improve our financial flexibility:
- Identify new sources of liquidity to strengthen our balance sheet and fund new opportunities, including development drilling;
- Subject to government and partner approvals, undertake the next Etame Marin block drilling program in 2018;
- Focus on maintaining production and lowering costs to increase margins and preserve optionality to capitalize on an increase in prices;
- Continue our focus on operating safely and complying with internationally accepted environmental operating standards;
- Optimize production through careful management of wells and infrastructure, including minimizing downtime;
- Further reduce field-level costs;
- Minimize administrative costs; and
- Opportunistically hedge against exposures to changes in oil prices.

We believe that we have strong management and technical expertise specific to West Africa, and that our strengths include the following:

- Our reputation as a West Africa operator;
- Our history of establishing favorable operating relationships with host governments and local partners;
- Our subsurface knowledge of key plays and risks in the broader regional framework of discoveries and fields;

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· Our operational capacity to take on new development projects;
· Our familiarity with local practices and infrastructure; and
· Our market intelligence to provide early insight into available opportunities.

SEGMENT AND GEOGRAPHIC INFORMATION

For operating segment and geographic financial information, see Note 15 to the Financial Statements. Our only reportable operating segments are Gabon, Equatorial Guinea and the United States.

Gabon Segment

Offshore – Etame Marin Block

Our most significant asset, which accounts for approximately 100% of our current revenues, is the Etame PSC, which we signed in 1995, relating to the Etame Marin block located offshore Gabon. The Etame Marin block covers an area of approximately 28,700 gross acres and consists of subsalt reservoirs that lie 20 miles offshore in water depths of approximately 250 feet. The Etame, Avouma/South Tchibala, Ebouri, Southeast Etame and North Tchibala fields are included in the block. Our working interest in the Etame Marin block is now 31.1%, and we operate it on behalf of a consortium of four companies (which we refer to as the "consortium"). The development is subject to a 7.5% back-in interest by the government of Gabon, which they have assigned to a third party.

Etame field. In 2001, the Government of Gabon awarded to us and our consortium partners a 12,000 gross acre exploitation area for development of the Etame field. The exploitation area has a term of 20 years through June 2021, and includes the Southeast Etame field. There are currently five wells producing in the Etame field.

Avouma/South Tchibala field. We and our consortium partners have rights to a 13,000-gross acre exploitation area for the joint development of Avouma/South Tchibala field and the North Tchibala field, which expire in March 2025. Currently, one well in the Avouma/South Tchibala field is producing and two wells are temporarily shut-in pending workovers.

Ebouri field. We and our consortium partners have rights to a 3,700-gross acre exploitation area for the joint development of the Ebouri field, which expire in July 2026. Currently, we have one producing well in the Ebouri field.

Southeast Etame. We drilled one well in the Southeast Etame field in 2015, and this well is continuing to produce. The Southeast Etame field is included in the exploitation area for the Etame field which has a term of 20 years through June 2021.

North Tchibala field. We drilled two wells in the North Tchibala field in 2015. These wells targeted the Dentale formation, and are producing currently. The North Tchibala field is included in the exploitation area for the Avouma/South Tchibala field. This exploitation area expires in March 2025.

Development. Following the installation of the platform for the Etame field and the platform for the Southeast Etame/North Tchibala fields in 2014, we commenced drilling the first well of a multi-well drilling campaign in 2014. As a result of this campaign, in 2015, two new development wells were drilled in the Etame field and brought on production, and three new development wells were drilled and brought on production in the Southeast Etame field and the North Tchibala field. The first well drilled was not placed on production due to high levels of hydrogen sulfide ("H_2S") present in fluids produced from the well. See "— Hydrogen Sulfide Impact" below.

The Constellation II drilling rig that we had contracted in 2014 and 2015 for these operations performed workover operations in late 2015 and early 2016. In February 2016, due to the continuing low commodity price regime, we released the rig and incurred expenses of $7.9 million in 2016, net to us, related to its demobilization and early release. These expenses are reflected in “Other operating expenses” in the Financial Statements. See also Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Rig commitment.”

During the first quarter of 2016, we conducted workover operations on two Avouma field wells. An Electrical Submersible Pump (“ESP”) system was replaced successfully in one well, but the workover operations on the second well were suspended due to operational problems. During the second and third quarters of 2016, the ESPs in the South Tchibala 2-H well and the Avouma 2-H well also failed. These wells were temporarily shut-in, but through our utilizing a lower-cost hydraulic workover unit to replace the failed ESP systems, the two wells were placed back on production in December 2016 and January 2017, respectively.

On November 22, 2016, we closed on the purchase of an additional 2.98% working interest (3.23% participating interest) in the Etame Marin block from Sojitz Etame Limited (“Sojitz”), which had an effective date of August 1, 2016. See Note 5 of the Financial Statements for further discussion.

In July 2017, the ESP in the South Tchibala 2-H well failed, resulting in the well being temporarily shut-in.

In October 2017, we began workover operations on the South Tchibala 1-HB well. These operations were successfully completed in November 2017, and the well was returned to production. However, this well experienced an ESP failure in late December, and it remains temporarily shut-in. We began workover operations on the South Tchibala 2-H well in November 2017. These operations were successfully completed in November 2017, and the well was returned to production. In November 2017, the Avouma 2-H well experienced ESP failures, and the well remains temporarily shut-in. We are working with the manufacturer and other technical consultants to investigate the root causes of the ESP failures. Excluding the Avouma platform wells, the wells on the other three platforms with ESPs have operated without incident for up to four years.

During July 2017, production was temporarily shut-in for periodic maintenance, and as a result, production volumes were lower in the three months ended September 30, 2017 and our production expense increased as a result of the maintenance-related costs.

Our current net production is averaging approximately 3,500 barrels of oil equivalent per day (BOEPD), down from a 4,160 barrels of oil equivalent per day (BOEPD) average for fiscal 2017 as a result of natural decline and temporarily shutting in the Avouma 2-H well.

For 2017, our total proved reserves replacement was 127% of our 2017 total net production in Gabon. See "— Reserve Information" below. These results occurred primarily due to (i) better-than-forecasted results for production and (ii) increased crude oil prices.

Production. Production operations in the Etame Marin block include nine platform wells, plus three subsea wells across all fields tied back by pipelines to deliver oil and associated natural gas through a riser system to allow for delivery, processing, storage and ultimately offloading the oil from a leased FPSO vessel anchored to the seabed on the block. Production from seven of our wells is aided by ESPs. We currently have ten producing wells and two wells shut in at Avouma due to ESP failures. The FPSO has production limitations of approximately 25,000 BOPD and 30,000 barrels of total fluids per day. For the years ended December 31, 2017, 2016 and 2015, aggregate production from the block was approximately 5.6 MMBbls (1.5 MMBbls net to us), 6.2 MMBbls (1.5 MMBbls net to us) and 6.8 MMBbls (1.7 MMBbls net to us), respectively. Our net share of barrels produced reflects an allocation of cost oil and profit oil after reduction for a royalty of approximately 13%.

Hydrogen Sulfide Impact

Four of our wells are currently shut-in for safety and marketability reasons because of high levels of H_2S. These wells have been excluded from the above-referenced well count. To re-establish and maximize production from the impacted areas, additional capital investment will be required, including the construction of one or more processing facilities capable of removing H_2S, the recompletion of the temporarily abandoned wells and the potential drilling of additional wells. These identified processing facilities are not economic at current forecasted oil prices. As of December 31, 2017, we had no proved reserves booked for the wells impacted by high levels of H_2S.

Exploration

At December 31, 2017, we had no undeveloped leasehold costs related to the Etame Marin block. The sixth extension period of the exploration acreage on the Etame Marin block expired at the end of July 2014, with the Consortium having fully met all of the obligations under its terms.

Abandonment Costs

As part of securing the first of two five-year extensions to the Etame field production license to which we were entitled from the government of Gabon, we agreed to a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. The agreement was finalized in 2014, but effective for 2011 forward, providing for annual funding over a period of ten years at 12.14% of the total abandonment estimate for the first seven years, with annual payments for the remaining unfunded estimated costs spread over the last three years of the production license.

We are required under the Etame PSC to conduct abandonment studies to update the amounts being funded for the eventual abandonment of the offshore wells, platforms and facilities on the Etame Marin block. The current abandonment study was completed in January 2016 resulting in estimated gross abandonment costs of approximately $61.1 million ($19.0 million net to VAALCO) on an undiscounted basis. Through December 31, 2017, $34.8 million ($10.8 million net to VAALCO) on an undiscounted basis has been funded. The annual abandonment cost requirements net to VAALCO are expected to be $2.3 million in 2018, and $4.9 million over the years from 2019 to 2021, net of estimated interest income. Amounts paid are reimbursable through the cost account and are non-refundable. Our estimated liabilities for the abandonment of these Gabon offshore facilities as of December 31, 2017 and 2016 were $20.2 million and $18.6 million, respectively, which are included in the total "Asset retirement obligation" line item on our consolidated balance sheets as of December 31, 2017 and 2016. Initial recording of this liability is offset by a corresponding capitalization of asset retirement costs reflected under "Property and equipment – successful efforts method" in the line item "Wells, platforms and other production facilities" on our consolidated balance sheets as of December 31, 2017 and 2016.

Onshore – Mutamba Iroru Block

We have a 50% working interest (41% net working interest assuming the Republic of Gabon exercises its back-in rights) and have been designated as the operator of the Mutamba Iroru block located onshore Gabon. Because of the lower projected oil price data in 2015, we wrote off our investment in this block in 2015, charging all costs, including capitalized exploratory well costs, to exploration expense. The government of Gabon believes that our production sharing contract for this block expired in mid-2014. While we maintain that the PSC is still valid, we expect that a new PSC would be required in order to pursue development, and we would only enter into a new PSC in the event that the project becomes economic. We can provide no assurances as to either the approval of a new PSC, or any subsequent approval of a development plan by the Government of Gabon.

Equatorial Guinea Segment

We have a 31% working interest in an undeveloped portion of Block P offshore Equatorial Guinea that we acquired in 2012. It is currently unlikely that we will be making any near-term expenditures with respect to any development of this property. We and our partners will need to evaluate the timing and budgeting for exploration and development activities under a development and production area in the block, including the approval of a development and production plan to develop the Venus discovery on the block. Our production sharing contract covering this development and production area provides for a development and production period of 25 years from the date of approval of a development and production plan.

United States Segment

In April 2017, we completed the sale of our interests in the East Poplar Dome field in Montana for $0.3 million, resulting in a gain of approximately $0.3 million during the year ended December 31, 2017. In December 2016, we completed the sale of our interests in two producing wells in the Hefley field (Granite Wash formation) in North Texas for $0.8 million, resulting in an immaterial loss. Our remaining interests in the U.S. are inconsequential.

Organization of Petroleum Exporting Countries (“OPEC”) Production Reductions

In November 2016, OPEC reached a decision to reduce its level of production effective January 1, 2017. Gabon, as a member of OPEC, agreed to reduce its production by up to 9,000 Bbl per day. In November 2017, OPEC reached a decision to extend the period of the reduced production levels through December 2018. As a result of natural production declines, production in 2017 was not impacted by this agreement, and for 2018 we do not expect our production or drilling plans will be impacted by the agreement.

DRILLING ACTIVITY

The table below reports the results of our drilling activity for each of the last three years. The “International” geographic designation for the prior three years was comprised solely of Gabon.

	International						
	Gross				Net		
	2017	2016	2015		2017	2016	2015
Exploratory wells							
Productive	—	—	—		—	—	—
Dry	—	—	1.0	(1)	—	—	0.5
In progress	—	—	—		—	—	—
Development wells	—	—	—		—	—	—
Productive	—	—	6.0	(2)	—	—	1.8
Dry	—	—	—		—	—	—

In progress	—	—	—	—	—	—
Total wells	—	—	7.0	—	—	2.3

(1)N'Gongui No. 2 discovery well, which had been suspended since being drilled onshore Gabon in 2012 and was deemed to be unsuccessful in 2015. Excludes an unsuccessful well associated with discontinued operations in Angola.

(2)Includes the Etame 8-H well that was in progress at December 31, 2014, evaluated for H_2S in 2015 and then shut-in when the presence of high levels of H_2S was confirmed.

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ACREAGE AND PRODUCTIVE WELLS

Below is the total acreage under lease or covered by the PSC and the total number of productive oil and natural gas wells as of December 31, 2017:

	International		
Acreage in thousands	Gross		Net
Developed acreage	28.7		8.9
Undeveloped acreage	327.0		128.0 (1)
Productive natural gas wells	—		—
Productive oil wells	12.0	(2)	3.7

(1)

(1) We have net undeveloped acreage of 110,000 acres onshore Gabon and 18,000 acres offshore Equatorial Guinea.

(2) Includes two Avouma wells temporarily shut-in pending workovers. Excludes the Etame 8-H, the Etame 5-H and two Ebouri field wells shut-in due to the presence of high levels of H_2S.

RESERVE INFORMATION

Net Proved Reserves

In accordance with the current guidelines of the SEC, estimates of future net cash flow from our properties and the present value thereof are made using an unweighted, arithmetic average of the first-day-of-the-month price for each of the 12 months of the year adjusted for quality, transportation fees and market differentials. Such prices are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For 2017, the average of such price used for our reserve estimates was $53.49 per Bbl for crude oil from Gabon. This compares to the average of such price used for 2016 of $40.35 per Bbl.

Reserves are reported by geographic area. International consists solely of net proved reserves related to the Etame Marin block located offshore Gabon in West Africa. We have no proved reserves related to our other international ventures and as a result of the sale of the Hefley wells in December 2016, we have no proved reserves in the United States. There have been no estimates of total proved net oil or natural gas reserves filed with or included in reports to any federal authority or agency other than the SEC since the beginning of the last fiscal year. Natural gas volumes include natural gas liquid (“NGL”) barrels which were converted to Mmcf using the relative prices of the products. The table below sets forth our estimated net proved reserve quantities for the years ended December 31, 2017, 2016, and 2015 as prepared by NSAI, independent petroleum engineers.

	As of December 31,		
	2017	2016	2015
	(in thousands)		
Crude oil			
Proved developed reserves (MBbls)			
International	3,049	2,642	2,840
United States	—	—	15
Total proved developed reserves (MBbls)	3,049	2,642	2,855
Proved undeveloped reserves (MBbls)			
International	—	—	—
United States	—	—	—
Total proved undeveloped reserves (MBbls)	—	—	—
Total proved reserves (MBbls)			
International	3,049	2,642	2,840
United States	—	—	15
Total proved reserves (MBbls)	3,049	2,642	2,855
Natural gas			
Proved developed reserves (MMcf)			
International	—	—	—
United States	—	—	1,053
Total proved developed reserves (MMcf)	—	—	1,053
Total proved reserves (MMcf)			
International	—	—	—
United States	—	—	1,053
Total proved reserves (MMcf)	—	—	1,053
Total proved reserves (MBOE)	3,049	2,642	3,031
Standardized measure of discounted future net cash flows	$ 22,490	$ 9,441	$ 27,141

Changes in Proved Reserves

The following table shows changes in total proved reserves for all presented years

	Proved Reserves		
	Crude Oil (MBbls)	Natural Gas (MMCF)	Oil Equivalent (MBOE)
	(in thousands)		
Balance at January 1, 2015	8,260	1,406	8,494
Production	(1,659)	(181)	(1,688)
Revisions of previous estimates	(3,746)	(172)	(3,775)
Balance at December 31, 2015	2,855	1,053	3,031
Production	(1,518)	(124)	(1,539)
Purchases of minerals in place	308	—	308
Sales of minerals in place	(12)	(929)	(167)
Revisions of previous estimates	1,009	—	1,009
Balance at December 31, 2016	2,642	—	2,642
Production	(1,518)	—	(1,518)
Revisions of previous estimates	1,925	—	1,925
Balance at December 31, 2017	3,049	—	3,049

The information set forth in the foregoing tables includes revisions for certain reserve estimates attributable to proved properties included in preceding years' estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of an increase or decrease in the projected economic life of such properties resulting from changes in product prices. Crude oil amounts shown for Gabon are recoverable under a PSC, and the reserves in place at the end of the contract remain the property of the Gabon government. The reserves at the end of the contract are not included in the table above.

We do not reflect proved reserves on discoveries in our reserve estimates until such time as a development plan has been prepared and approved by our partners and the government, where applicable.

The upward revision of the previous estimates in 2017 was primarily a result of improved well performance and to a lesser degree the higher average crude oil prices.

The upward revision of the previous estimates in 2016 was primarily a result of improved well performance and lower costs. Purchases of minerals in place in 2016 was related to the additional 2.98% working interest in the Etame Marin block we acquired from Sojitz Etame Limited (“Sojitz”) in November 2016. The lower average crude oil price used for 2016 estimates only partially offset the favorable impacts of well performance, operating cost reductions, and the other factors. Sales of minerals in place in 2016 is related to the sale of the Hefley field in the U.S. in December 2016.

The net negative revisions of previous estimates in 2015 were primarily a result of the loss of 3.5 years of production due to lower oil and natural gas prices (2,705 MBOE) and the removal of sour oil reserves (1,440 MBbl), partially offset by positive revisions due to the performance of wells drilled in the 2014-2015 drilling campaign exceeding expectations (370 MBbl). The average oil price used to value reserves for 2015 was $49.36 per Bbl, which is almost 50% lower than the $98.88 per Bbl used for 2014 reserves. This price decrease accelerated the economic cutoff date for the Etame Marin block reserves from December 2021 as of the end of 2014 to May 2018 as of the end of 2015. Investigations into the cause of the crude souring indicate that the effect was not as widespread as previously projected. As discussed in “Hydrogen Sulfide Impact” above, crude sweetening options were uneconomic in the depressed commodity price environment.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas sales prices may all differ from those assumed in these estimates. The standardized measure of discounted future net cash flows should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties.

Proved Undeveloped Reserves

Historically, we have reviewed on an annual basis all of our proved undeveloped reserves (“PUDs”) to ensure an appropriate plan for development exists. As a result of the current crude oil prices in 2017, our PUDs are uneconomic to develop at prices calculated in accordance with SEC guidelines. Accordingly, we had no PUDs recorded at December 31, 2017, 2016 and 2015.

Controls over Reserve Estimates

Our policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and natural gas reserves quantities and present values in compliance with SEC regulations and generally accepted accounting principles in the U.S. (“GAAP”). Compliance with these rules and regulations with respect to our reserves is the responsibility of a reservoir engineer, who is our principal engineer. Our principal engineer has over 20 years of experience in the oil and natural gas industry, including over 10 years as a reserve evaluator and trainer, and is a qualified reserves estimator, as defined by the Society of Petroleum Engineers’ standards. Further professional qualifications include a Bachelor’s degree in mechanical engineering and Master’s degree in petroleum engineering, extensive internal and external reserve training, and asset evaluation and management. In addition, the principal engineer is an active participant in industry reserve seminars, professional industry groups and is a member of the Society of Petroleum Engineers. The Audit Committee of the Board of Directors meets periodically with management to discuss matters and policies related to reserves.

Our controls over reserve estimation include retaining NSAI as our independent petroleum and geological firm for all years presented. We provide information to NSAI about our oil and natural gas properties which includes, but is not limited to, production profiles, ownership and production sharing rights, prices, costs and future drilling plans. NSAI prepares its own estimates of the reserves attributable to our properties. The reserves estimates shown herein have been independently evaluated by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. John R. Cliver and Mr. Zachary R. Long. Mr. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. He graduated from Rice University in 2004 with a Bachelor of Science Degree in Chemical Engineering and from University of Texas at Austin in 2008 with a Master of Business Administration Degree. Mr. Long, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience. He graduated from University of Louisiana at Lafayette in 2003 with a Bachelor of Science Degree in Geology and from Texas A&M University in 2005 with a Master of Science Degree in Geophysics.

Net Volumes sold, Prices, and Production Costs

Net volumes sold, average sales prices per unit, and production costs per unit for our 2017, 2016, and 2015 operations are shown in the tables below.

	Year Ended December 31, 2017			2016			2015		
	Oil Equivalent (MBOE)	Oil and Condensate (MBbl)	Natural Gas(MMcf)	Oil Equivalent (MBOE)	Oil and Condensate (MBbl)	Natural Gas(MMcf)	Oil Equivalent (MBOE)	Oil and Condensate (MBbl)	N G
Net production sold									
International	1,423	1,423	—	1,485	1,485	—	1,679	1,679	–
United States	—	—	—	24	3	124	33	3	18
Total production sold	1,423	1,423	—	1,509	1,488	124	1,712	1,682	18

	Year Ended December 31, 2017			2016			2015	
	Oil Equivalent ($/BOE)	Oil and Condensate ($/Bbl)	Natural Gas($/Mcf)	Oil Equivalent ($/BOE)	Oil and Condensate ($/Bbl)	Natural Gas($/Mcf)	Oil Equivalent ($/BOE)	Oil and Condensa ($/Bbl)
Average sales price								
International	$ 52.58	$ 52.58	$ —	$ 40.17	$ 40.17	$ —	$ 47.87	$ 47.87
United States	—	—	—	13.50	23.54	1.95	15.09	32.67
Overall average sales price	52.58	52.58	—	39.62	40.13	1.95	47.24	47.85

	Year Ended December 31,		
	2017	2016	2015
Average production expense per MBOE			
International	$ 27.90	$ 25.22	$ 23.79
United States	—	5.58	4.67
Overall average production expense	27.90	24.91	23.42

DISCONTINUED OPERATIONS-ANGOLA

On September 30, 2016, we notified Sonangol P&P, our joint venture partner, that we were withdrawing from the joint operating agreement effective October 31, 2016. Further to our decision to withdraw from Angola, we have closed our office in Angola and do not intend to conduct future activities in Angola. As a result of this strategic shift, the Angola segment has been classified as discontinued operations in the Financial Statements for all periods presented. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Discontinued Operations - Angola.”

AVAILABLE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document we file at the SEC’s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the SEC’s Public Reference Room. Our SEC filings are also available to the public at the SEC’s website at www.sec.gov.

You may also obtain copies of our annual, quarterly and current reports, proxy statements and certain other information filed with the SEC, as well as amendments thereto, free of charge from our website at www.vaalco.com. No information from the either the SEC’s or our website is incorporated by reference herein. We have placed on our website copies of our Audit Committee Charter, Code of Business Conduct and Ethics, and Code of Ethics for the Chief Executive Officer and Chief Financial Officer. Stockholders may request a printed copy of these governance materials by writing to the Corporate Secretary, VAALCO Energy, Inc., 9800 Richmond Avenue, Suite 700, Houston, Texas 77042.

CUSTOMERS

For the period from the second quarter of 2014 and through April 2015, our crude oil from Gabon was sold under a contract with The Vitol Group at the spot market for a fixed per barrel fee. Beginning in May 2015, we sold our crude oil production from Gabon under a term contract with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. The contracted purchasers were TOTSA Total Oil Trading SA (“Total”) for May through July of 2015 and Glencore Energy UK Ltd. (“Glencore”) beginning in August of 2015. The contract with Glencore expires in January of 2019. Sales of oil to Glencore were approximately 100% of total revenues for 2017.

EMPLOYEES

As of December 31, 2017, we had 102 full-time employees, 75 of whom were located in Gabon. We are not subject to any collective bargaining agreements, although some of the national employees in Gabon are members of the NEOP (National Organization of Petroleum Workers) union. We believe relations with our employees are satisfactory.

COMPETITION

The oil and natural gas industry is highly competitive. Competition is particularly intense from other independent operators and from major oil and natural gas companies with respect to acquisitions and development of desirable oil and natural gas properties and licenses, and contracting for drilling equipment. There is also competition for the hiring of experienced personnel. In addition, the drilling, producing, processing and marketing of oil and natural gas is affected by a number of factors beyond our control which may delay drilling, increase prices and have other adverse effects which cannot be accurately predicted.

Our competition for acquisitions, exploration, development and production includes the major oil and natural gas companies in addition to numerous independent oil companies, individual proprietors, investors and others. Many of these competitors have financial and technical resources and staff that are substantially larger than ours. As a result, our competitors may be able to pay more for desirable oil and natural gas assets, or to evaluate, bid for and purchase a greater number of properties and licenses than our financial or personnel resources will permit. Furthermore, these companies may also be better able to withstand the financial pressures of lower commodity prices, unsuccessful wells, volatility in financial markets and generally adverse global and industry-wide economic conditions. These companies may also be better able to absorb the burdens resulting from changes in relevant laws and regulations, which may adversely affect our competitive position. Our ability to generate reserves in the future will depend on our ability to select and acquire suitable producing properties and/or developing prospects for future drilling and exploration.

INSURANCE

For protection against financial loss resulting from various operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/control of a well, comprehensive general liability, worker’s compensation and employer’s liability. We maintain insurance at levels we believe to be customary in the industry to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of certain prohibited substances into the environment. Such insurance might not cover the complete claim amount and would not cover fines or penalties for a violation of environmental law. We are not fully insured against all risks associated with our business either because such insurance is unavailable or because premium costs are considered uneconomic. A material loss not fully covered by insurance could have an adverse effect on our financial position, results of operations or cash flows.

REGULATORY

General

Our operations and our ability to finance and fund our operations and growth are affected by political developments and laws and regulations in the areas in which we operate. In particular, oil and natural gas production operations and economics are affected by:

- change in governments;
- civil unrest;
- price and currency controls;
- limitations on oil and natural gas production;
- tax, environmental, safety and other laws relating to the petroleum industry;
- changes in laws relating to the petroleum industry;
- changes in administrative regulations and the interpretation and application of administrative rules and regulations; and
- changes in contract interpretation and policies of contract adherence.

In any country in which we may do business, the oil and natural gas industry legislation and agency regulation are periodically changed, sometimes retroactively, for a variety of political, economic, environmental and other reasons. Numerous governmental departments and agencies issue rules and regulations binding on the oil and natural gas industry, some of which carry substantial penalties for the failure to comply. The regulatory burden on the oil and natural gas industry increases our cost of doing business and our potential for economic loss.

Gabon

Our exploration and production activities offshore Gabon are subject to Gabonese regulations. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that could substantially increase our costs or affect our operations. The following is a summary of certain applicable regulatory frameworks in Gabon.

In 2014, a new Hydrocarbons Law entered into force to regulate oil and gas activities in Gabon. It repealed some prior laws relating to oil activities as well as all contradictory regulations contained in the remaining non-repealed laws of the oil and gas sector.

Pursuant to the Hydrocarbons Law, petroleum resources in Gabon are the property of the State of Gabon and petroleum companies undertake operations on behalf of the Government of Gabon. In order to conduct petroleum operations, oil and gas companies must enter into a hydrocarbons agreement, typically an exploration and production sharing contract, which is signed on behalf of the State by the Minister in charge of Hydrocarbons and the Minister in charge of Economy. Such agreement is subject to enactment by Presidential Decree, and its provisions must conform to the Hydrocarbons Law, subject to being null and void.

Furthermore, under Article 260 of the 2014 Hydrocarbons Law, all oil and gas companies, even those carrying out operations under the previous legal framework, must make payment of two financial contributions set forth in the new Hydrocarbons Law, namely the Investment Diversification Fund (payment of 1% of the Contractor’s turnover during the production phase), and the Hydrocarbons Investment Fund (payment of 2% of the Contractor’s turnover during the production phase), within two years of the entry into force thereof. Under Article 260, oil and gas companies must also, within a maximum of one year from publication of the Hydrocarbons Law, set up and domicile the site rehabilitation funds for the Hydrocarbon activities at the Banque des Etats de l’Afrique Centrale or at a Gabonese banking or financial institution.

The Hydrocarbons Law provides for a detailed legal framework in terms of organization of the sector, contents and terms and conditions of hydrocarbons agreements, liability, local content, safety and environment, domestic supply requirements, fiscal terms such as production sharing, royalty, bonuses and other charges, corporate income tax, customs, and local training obligations.

The powers to make many of the day-to-day decisions concerning petroleum activities, including the granting of certain consents and authorizations, remain vested with the Hydrocarbons General Directorate, a government authority. In addition, the national oil company—Société Nationale des Hydrocarbures du Gabon—currently holds, manages and takes participations in petroleum activities on behalf of the State. Pursuant to Article 4 of the Hydrocarbons Law, the State may acquire an equity stake of up to 20%, at market value, within any companies applying for or already holding an exclusive production authorization. The contractor must carry the State in its 20% participating interest in the hydrocarbons agreements during the exploration phase. The parties are free to agree on a higher stake at market value. Further, under Article 86 of the Hydrocarbons Law, the national oil company may also acquire participating interests of up to 15%, at market value.

In addition to general labor regulations, which require that the workforce of any company in Gabon complies with a 90/10 ratio of Gabon national to foreign expatriate workers, pursuant to the Hydrocarbons Law, subcontracting activities are awarded in priority to Gabonese companies in which at least 80% of the workforce consists of Gabonese nationals. In this respect, only technically qualified license holders may be hired as subcontractors.

Under the 2014 Hydrocarbons Law, assignment of interests in production sharing contracts is subject to the Ministry of Hydrocarbons' consent and to the State's preemption rights. Foreign companies carrying out production activities under the form of a local branch must incorporate a local company within two years of the entry into force of the Hydrocarbons Law under its Article 254.

With respect to natural gas, the State shall enjoy exclusive marketing rights for non-associated gas while any non-commercial share of associated natural gas remains the property of the State.

Hydrocarbons agreements entered into prior to the Hydrocarbon Law's publication remain in force until their expiration and should continue to be governed by their own provisions. Our understanding is that the Hydrocarbons Law applies to any issues not expressly dealt with in these contracts' provisions.

Our production sharing contract governing our rights to the Etame Marin block offshore Gabon was entered into before the publication of the Hydrocarbon Law. The PSC contains a stabilization clause, which provides for the stability of the legal, tax, economic and financial conditions in force at the signing of the PSC. Pursuant to the PSC, these conditions may not be adversely altered during the term of the agreement; however, we can make no assurance that the interpretation of the Hydrocarbon Law will not adversely affect our operations or assets in Gabon.

As discussed in "— Segment and Geographic Information—Gabon Segment—Offshore – Etame Marin Block—Production," production from the Etame block is stored in an FPSO which we lease from a third party. Over the past 15 years, this vessel was imported under a temporary import license issued to us. Customs officials have advised us that the temporary import license cannot be renewed and that the owner of the FPSO, Tinworth Pte. Limited, an affiliate of BW Offshore Limited, needs to obtain a permanent import license in order to continue operating in Gabon. We are working to find other forms of relief. Should these other efforts fail and the vessel owner does not obtain the permanent import license, this could result in customs fines and penalties being owed by the vessel owner. We are also working with the owner to ensure that they meet the requirements to obtain the permanent import license. In connection with this regulatory matter, the Gabon government could take actions which would impede the operations of the FPSO if this is not resolved. This matter could have an adverse impact on our financial position, results of operations or cash flows.

ENVIRONMENTAL REGULATIONS

General

Our operations are subject to various federal, state, local and international laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection or pollution control subject to the laws and regulations of Equatorial Guinea if exploration drilling occurs in that country. The cost of compliance could be significant. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial and damage payment obligations, or the issuance of injunctive relief (including orders to cease operations). Environmental laws and regulations are complex and have tended to become more stringent over time. We also are subject to various environmental permit requirements. Some environmental laws and regulations may impose strict liability, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties. To the extent laws are enacted or other governmental action is taken that prohibits or restricts drilling or imposes environmental protection requirements that result in increased costs to the oil and natural gas industry in general, our business and financial results could be adversely affected. Although no assurances can be made, we believe that, absent the occurrence of an extraordinary event, compliance with existing laws, rules and regulations regulating the release of materials into the environment or otherwise relating to the protection of the environment will not have a material effect upon our capital expenditures, earnings or competitive position with respect to our existing assets and operations. We cannot predict what effect future regulation or legislation, enforcement policies, and claims for damages to property, employees, other persons and the environment resulting from our operations could have on our activities.

In addition, a number of governmental bodies have adopted, have introduced or are contemplating regulatory changes in response to various climate change non-governmental organizations and the potential impact of climate change. Legislation and increased regulation regarding climate change could impose significant costs on us, our venture partners, and our suppliers, including costs related to increased energy requirements, capital equipment, environmental monitoring and reporting, and other costs to comply with such regulations. Given the political significance and uncertainty around the impact of climate change and how it should be dealt with, we cannot predict how legislation and regulation will affect our financial condition and operating performance. In addition, increased awareness and any adverse publicity in the global marketplace about potential impacts on climate change by us or other companies in our industry could harm our reputation or impact the marketability of our product. The potential physical impacts of climate change on our operations are highly uncertain and would be particular to the geographic circumstances in areas in which we operate. These may include changes in rainfall and storm patterns and intensities, water shortages, changing sea levels, and changing temperatures. These impacts may adversely impact the cost, production, and financial performance of our operations.

In part because they are developing countries, it is unclear how quickly and to what extent Gabon or Equatorial Guinea will increase their regulation of environmental issues in the future; any significant increase in the regulation or enforcement of environmental issues by Gabon or Equatorial Guinea could have a material effect on us. Developing countries, in certain instances, have patterned environmental laws after those in the U.S., which are discussed below. However, the extent to which any environmental laws are enforced in developing countries varies significantly.

With regards to our development operations offshore West Africa, we are a member of Oil Spill Response Limited (OSRL), a global emergency and oil spill-response organization headquartered in London. OSRL has aircraft and equipment available for dispersant application or equipment transport, including active recovery boom systems and other booms that can be used for offshore or shoreline responses. In addition, OSRL can provide communications equipment, safety equipment, transfer pumps, dispersant application systems, temporary storage equipment, generators, boats and vessels and oiled wildlife equipment.

See Item 1A "Risk Factors" for further discussion on the impact of these and other regulations relating to environmental protection.

Environmental Regulations in the United States

Currently, we conduct no operations in the U.S. and have only inconsequential interests in two U.S. properties. However, our prior operations in the U.S., and any future operations we may conduct in the U.S., may subject us to certain liabilities under U.S. federal, state and local environmental regulations. In the U.S., environmental laws and regulations are administered by the U.S. Environmental Protection Agency ("EPA") and counterpart state agencies in the various states where operations are conducted.

These U.S. laws and regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water, and disposals or other releases to surface and below-ground soils and ground water. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the permitting, development, or expansion of projects; and the issuance of injunctions restricting or prohibiting some or all of our activities in a particular area. Moreover, multiple environmental laws provide for citizen suits, which allow environmental organizations to act in the place of the government and sue operators for alleged violations of environmental law.

Some of our prior operations on U.S. onshore properties involved hydraulic fracturing activities associated with drilling in shale formations. Hydraulic fracturing has been increasingly the subject of significant focus among many non-governmental organizations and regulators. Hydraulic fracturing requires the use and disposal of water, and public concern has been growing over its possible effects on drinking water supplies, as well as the adequacy of both water supply sources and disposal methods.

Superfund

We have previously owned or leased properties in the U.S. used for the exploration and production of oil and natural gas. Although we may have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed or released on or under the properties owned or leased by us or on or under locations where such wastes have been taken for disposal. In addition, some of these properties are or have been operated by third parties. We have no control over such entities' treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. We could, in the future, be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed or released by prior owners or operators, or property contamination, including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future contamination or mitigate existing contamination.

The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, generally imposes joint and several liability for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances ("Hazardous Substances"). These classes of persons, or so-called potentially responsible parties ("PRPs"), include the current and certain past owners and operators of a facility where there has been a release or threat of release of a Hazardous Substance and persons who disposed of or arranged for the disposal of Hazardous Substances found at a facility. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the PRPs the costs of such action.

Although CERCLA generally exempts "petroleum" from the definition of a Hazardous Substance, in the course of our prior U.S. operations, we may have generated substances that may fall within CERCLA's definition of a "Hazardous Substance" and may have disposed of these substances at disposal sites owned and operated by others. Also, properties that we own and properties that we may have owned or operated may have been sites on which Hazardous Substances have been released. To our knowledge, neither we nor our predecessors have been designated as a PRP by the EPA under CERCLA; we also do not know of any prior owners or operators of its properties that are named as PRPs related to their ownership or operation of such properties. States such as Texas have comparable statutes which may cover substances (including petroleum) in addition to those covered under CERCLA. In the event contamination is discovered at a site on which we have been an owner or operator or to which we sent regulated substances, we could be liable for costs of investigation and remediation and damages to natural resources.

The Oil Pollution Act of 1990

The Oil Pollution Act of 1990 ("OPA"), which amends and augments the oil spill provisions of the Clean Water Act ("CWA") imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening U.S. waters or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, we may be liable for costs and damages. The OPA also imposes ongoing requirements on a responsible party, including proof of financial responsibility to cover at least some costs in a potential spill.

Other Environmental Regulation in the U.S.

In the past, we may have generated wastes, including hazardous wastes that are subject to the federal Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes which may limit disposal options. Although most oil and natural gas wastes are exempt from regulation as a hazardous waste under RCRA at the federal level, not all comparable state statutes may have provided the same exemption, and certain wastes that we previously generated may have been subject to RCRA or comparable state statutes.

The CWA and analogous state laws impose restrictions and strict controls regarding the discharge (including spills and leaks) of pollutants, including produced waters and other oil and natural gas wastes as well as fill materials, into state waters and waters of the U.S., a term broadly defined but which remains subject to litigation and rulemaking over the scope of related waters.

The Clear Air Act and analogous state laws govern emissions from sources of air pollution. These laws may require new and modified sources of air pollutants to obtain permits prior to commencing construction and may require the installation of stringent control methods.

The Endangered Species Act (“ESA”) was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species’ habitat. A critical habitat or suitable habitat designation by the U.S. Fish and Wildlife Service could also result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development.

Most environmental programs provide for fines, penalties and injunctive relief for violations of their requirements. Some programs additionally provide for citizen suits, which allow a private citizen to sue to enforce the requirements of the applicable regulatory program.

Item 1A. Risk Factors

Our business faces many risks. You should carefully consider the following risk factors in addition to the other information included in this report. If any of these risks or uncertainties actually occurs, our business, financial condition and results of operations could be materially adversely affected. Any risks discussed elsewhere in this Form 10-K and in our other SEC filings could also have a material impact on our business, financial position or results of operations. Additional risks not presently known to us or which we consider immaterial based on information currently available to us may also materially adversely affect us.

Oil and natural gas prices are highly volatile, and a return to a very depressed price regime for a prolonged period of time will negatively affect our financial results.

Our revenues, cash flow, profitability, oil and natural gas reserves value and future rate of growth are substantially dependent upon prevailing prices for oil and natural gas. Our ability to borrow funds and to obtain additional capital on reasonable terms is also substantially dependent on oil and natural gas prices. Historically, world-wide oil and natural gas prices and markets have been volatile, and may continue to be volatile in the future. In particular, the prices of oil and natural gas declined dramatically in the second half of 2014 and decreased further in 2015 and early 2016. During 2015, based on New York Mercantile Exchange (“NYMEX”) pricing, the spot price per Bbl of Brent crude oil ranged from a high of $66 to a low of $35. During 2016, the spot price per Bbl of Brent crude oil ranged from a high of $55 to a low of $26. During 2017, the spot price per Bbl of Brent crude oil ranged from a high of $67 to a low of $44.

As a result of the low oil and natural gas prices since 2014, our revenues, operating income, cash flows and borrowing capacity have been materially and adversely affected and have required reductions in the carrying value of our oil and natural gas properties and our planned level of capital expenditures. The average price at which we sold our crude oil in 2017 was $52.58 per Bbl compared to $40.13 per Bbl in 2016 and $47.85 per Bbl in 2015. Because the oil price we are required to use by the SEC to estimate our future net cash flows is the average price over the 12 months prior to the date of determination of future net cash flows, the full effect of increasing or falling prices may not be reflected in our estimated net cash flows for several quarters. We review the carrying value of our properties on a quarterly basis and once incurred, a write-down in the carrying value of our properties is not reversible at a later date, even if oil and natural gas prices increase.

Prices for oil and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include, but are not limited to, increases in supplies from U.S. shale production, international political conditions, including uprisings and political unrest in the Middle East and Africa, the domestic and foreign supply of oil and natural gas, actions by OPEC member countries and other state-controlled oil companies to agree upon and maintain oil price and production controls, the level of consumer demand which is impacted by economic growth rates, weather conditions, domestic and foreign governmental regulations and taxes, the price and availability of alternative fuels, the health of international economic and credit markets, and general economic conditions. In addition, various factors, including the effect of federal, state and foreign regulation of production and transportation, general economic conditions, changes in supply due to drilling by other producers and changes in demand may adversely affect our ability to market our oil and natural gas production.

Unless we are able to replace the proved reserve quantities that we have produced, our cash flows and production will decrease over time.

At December 31, 2017 and 2016, we had no proved undeveloped reserves. We may have higher capital expenditures for our development activities during 2018 should we undertake the drilling of two or three development wells in Gabon. Drilling activities would be subject to partner and government approval.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. In general, production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves would be limited to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. Except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, our estimated net proved reserves will generally decline as reserves are produced.

There can be no assurance that our development and exploration projects and acquisition activities will result in significant additional reserves or that we will have continuing success drilling productive wells at economic finding costs. The drilling of oil and natural gas wells involves a high degree of risk, especially the risk of dry holes or of wells that are not sufficiently productive to provide an economic return on the capital expended to drill the wells. In addition, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including declines in oil or natural gas prices, title problems, weather conditions, political instability, availability of capital, economic/currency imbalances, compliance with governmental requirements, receipt of additional seismic data or the reprocessing of existing data, prolonged periods of historically low oil and natural gas prices, failure of wells drilled in similar formations, equipment failures (such as our experience with our electronic submersible pumps in 2016 and 2017 – see Item 1.

"Business – Segment and Geographic Information – Gabon Segment – Development"), delays in the delivery of equipment and availability of drilling rigs. Our Equatorial Guinea property is operated by third parties and, as a result, we have limited control over the nature and timing of exploration and development of such properties or the manner in which operations are conducted on such properties.

All of the value of our production and proved reserves is concentrated in a single block offshore Gabon, and any production problems or reductions in reserve estimates related to this property would adversely impact our business.

The Etame Marin block consists of five fields with 12 producing wells, including two wells which are temporarily shut-in pending workover operations. Production from these fields constituted approximately 99% of our total production for the year ended December 31, 2017. In addition, at December 31, 2017, 100% of our total net proved reserves were attributable to these fields. If mechanical problems, storms or other events curtailed a substantial portion of this production, or if the actual reserves associated with this producing property are less than our estimated reserves, our results of operations, financial condition, and cash flows could be materially adversely affected.

Because our properties are concentrated in the same geographic area, many of our rights under the PSC will be affected by the same conditions at the same time, resulting in a relatively greater impact on our results of operations than with respect to companies that have a more diversified portfolio of licenses and properties located across diverse geographic areas. In addition, there is no guarantee that we will be able to extend the life of the PSC beyond its current expiration dates, the first of which is in 2021.

In January 2016, we announced the formation of a strategic committee of our board of directors to oversee the consideration of various strategic alternatives potentially available to us in order to maximize our value.

A strategic committee of our directors formed by our board of directors in January 2016 is authorized to explore strategic options for VAALCO, including, but not limited to, securing additional investment to support existing projects and growth opportunities, joint ventures, asset sales or farm-outs, our potential sale or merger, or continuing to pursue our existing operating plan. We will continue to pursue ways to increase our liquidity. However, we can give no assurances that any of these strategic alternatives can be completed, and if so, on reasonable terms that are acceptable to us.

The formation of the strategic committee was not in response to any proposal we received or any approach by a third party.

No decision has been made to engage in any particular transaction or transactions. There can be no assurance that the strategic committee or our board of directors will authorize the pursuit of any strategic alternative. Moreover, there can be no assurance with respect to the terms or the timing of any transaction, or whether any transaction will ultimately occur. Any potential transaction would be dependent upon a number of factors that may be beyond our control, including, among other factors, market conditions, industry trends, the interest of third parties in our areas of operation and the availability of financing to potential buyers on reasonable terms.

Exploring for, developing, or acquiring reserves is capital intensive and uncertain.

We may not be able to economically find, develop, or acquire additional reserves, or may not be able to make the necessary capital investments to develop our reserves, if our cash flows from operations decline or external sources of capital become limited or unavailable. Offshore drilling and development operations require capital-intensive techniques. If we do not replace the reserves we produce, our reserves revenues and cash flow will decrease over time, which will have an adverse effect on our business.

Our business requires significant capital expenditures, and we may not be able to obtain needed capital or financing on satisfactory terms or at all.

Our exploration and development activities are capital intensive. To replace and grow our reserves, we must make substantial capital expenditures for the acquisition, exploitation, development, exploration and production of oil and natural gas reserves. Historically, we have financed these expenditures primarily with cash flow from operations, debt, asset sales, and private sales of equity. We are the operator of the Etame Marin block offshore Gabon, and are thus responsible for contracting on behalf of all the remaining parties participating in the project. We rely on the timely payment of cash calls by our partners to pay for 66.43% of the offshore Gabon budget. The continued economic health of our partners could be adversely affected by low oil prices, thereby adversely affecting their ability to make timely payment of cash calls.

If low oil and natural gas prices, operating difficulties or declines in reserves result in our revenues being less than expected or limit our ability to borrow funds, or our partners fail to pay their share of project costs, we may be unable to obtain or expend the capital necessary to undertake or complete future drilling programs. Our ability to secure additional or replacement financing is currently limited. We cannot assure you that additional debt or equity financing or cash generated by operations will be available to meet our capital requirements. In addition, we currently have no availability for additional borrowings under our Amended Term Loan Agreement, and we may be unable to replace our Amended Term Loan Agreement with a new source of capital. The outstanding indebtedness under our term loan with the IFC matures in June 2019. Interest is due quarterly, and we began repaying the principal amounts of this outstanding indebtedness in March 2017. We may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or cash available under any financing sources is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to the development of our properties. Such a curtailment in operations could lead to a possible expiration of our PSCs and a decline in our estimated net proved reserves, and would likely adversely affect our business, financial condition and results of operations.

Our Amended Term Loan Agreement imposes significant restrictions on our current and future operations. If we default under the Amended Term Loan Agreement, the lender may act to accelerate our indebtedness, which would impact our ability to conduct our business and results of operations.

The $9.2 million principal outstanding at December 31, 2017 under our Amended Term Loan Agreement matures in June 2019, and requires quarterly principal and interest payments on the amounts currently outstanding through its maturity on June 30, 2019.

The Amended Term Loan Agreement contains a number of restrictive covenants that impose significant operating and financial restrictions on us, which may limit our ability to engage in acts that may be in our best interests. These covenants include restrictions on our ability to:

- incur additional indebtedness, guarantee debt or enter into any arrangement to assume or become obligated for financial or other obligations of another (except pursuant to a joint operating agreement);
- pay dividends on or make other distributions in respect of, or purchase or redeem, shares of our capital stock;
- prepay, redeem or repurchase certain debt;
- make loans, investments and other restricted payments;
- sell, transfer or otherwise dispose of assets;
- create or incur liens;
- sell, transfer or lease all or a substantial part of our assets (other than inventory or depleted or obsolete assets in the ordinary course of business);
- enter into non-arm’s-length transactions;
- incur or commit to make certain expenditures for fixed or other non-current assets;
- enter into lease agreements or arrangements, other than the FPSO contract and leases necessary to carry on our business;
- form any subsidiary;
- terminate, amend or grant consents or waivers with respect to certain material contracts;
- use the proceeds of loans other than as permitted by the Amended Term Loan Agreement;
- reduce certain of our working interests;
- modify our organizational documents;
- alter the business we conduct;
- undertake or permit any merger, spin-off, consolidation or reorganization; and
- enter into any derivative transaction without prior approval.

In addition, the Amended Term Loan Agreement includes certain financial ratios, including;

- a debt service coverage ratio of (i) net cash flows (plus a balance in an operating account) to (ii) debt service obligations, of at least 1.2:1 at each quarter end; and
- a ratio of (i) net debt as of the end of a fiscal quarter to (ii) earnings before interest, tax, depreciation and amortization, and exploration expenses (EBITDAX) for the trailing 12 months ended on the most recent quarter end, at less than 3.0:1, except the quarter-end limitation was raised to 5.0:1 for periods through December 31, 2016.

As of December 31, 2017, we were in compliance with all of our financial covenants under our Amended Term Loan Agreement. However, we can make no assurance that we will be able to continue to comply with these financial covenants in the future. Failure to maintain these covenants or otherwise negotiate amendments to the Amended Term Loan Agreement could require us to immediately pay down any outstanding amounts.

These covenants have the effect of restricting our ability to engage in certain actions, including potentially limiting our ability to sell assets or incur other additional indebtedness. Our ability to meet our net debt to EBITDAX ratio and our different coverage ratio requirements can be affected by events beyond our control, including changes in commodity prices. There can be no assurance that we will be able to comply with these covenants in future periods. In addition, if we receive any additional waivers or amendments to our Amended Term Loan Agreement, the lender may impose additional operating and financial restrictions on us.

A breach of the covenants under our Amended Term Loan Agreement could result in an event of default under the agreement. Such a default may allow the lender to accelerate payment of the indebtedness under the Amended Term Loan Agreement. Furthermore, if we were unable to repay the amounts due and payable under the Amended Term Loan Agreement, the lender could proceed against the collateral granted to it to secure that indebtedness.

If oil and natural gas prices decline materially, we may be required to take write-downs in the value of our oil and natural gas properties.

The estimated future net revenues attributable to our net proved reserves are prepared in accordance with current SEC guidelines, and are not intended to reflect the fair market value of our reserves. In accordance with the rules of the SEC, our reserve estimates are prepared using the un-weighted average price received for oil and natural gas based on closing prices on the first day of each month during the twelve-month period prior to the end of the reporting period. As a result of declines in prices and increased development well costs, during 2015, we recorded impairments totaling $81.3 million related to the Etame Marin block and to various fields in the U.S. During 2016 and 2017, no impairments were necessary related to the Etame Marin block. The sale of our interests in two wells in North Texas caused us to perform an impairment test, resulting in a $0.1 million impairment charge taken during the third quarter of

2016. Material declines in crude oil prices will cause the estimated quantities and present values of our reserves to be reduced, which may necessitate further write-downs.

Our offshore operations involve special risks that could adversely affect our results of operations.

Offshore operations are subject to a variety of operating risks specific to the marine environment. Our production facilities are subject to hazards such as capsizing, sinking, grounding, collision and damage from severe weather conditions. The relatively deep offshore drilling conducted by us involves increased drilling risks of high pressures and mechanical difficulties, including stuck pipe, collapsed casing and separated cable. The impact that any of these risks may have upon us is increased due to the low number of producing properties we own. We could incur substantial expenses that could reduce or eliminate the funds available for exploration, development or license acquisitions, or result in loss of equipment and license interests.

Exploration and development operations offshore Africa often lack the physical and oilfield service infrastructure present in other regions. As a result, a significant amount of time may elapse between an offshore discovery and the marketing of the associated oil and natural gas, increasing both the financial and operational risks involved with these operations. Offshore drilling operations generally require more time and more advanced drilling technologies, involving a higher risk of equipment failure and usually higher drilling costs. In addition, there may be production risks of which we are currently unaware. For example, the production of hydrogen sulfide at our Etame 8-H well, which caused us to shut in the well in December 2014, created unexpected production losses and delays in our development plans; see Item 1. "Business – Segment and Geographic Information – Hydrogen Sulfide Impact." The development of new subsea infrastructure and use of floating production systems to transport oil from producing wells, may require substantial time for installation or encounter mechanical difficulties and equipment failures that could result in loss of production, significant liabilities, cost overruns or delays.

In addition, in the event of a well control incident, containment and, potentially, cleanup activities for offshore drilling are costly. The resulting regulatory costs or penalties, and the results of third party lawsuits, as well as associated legal and support expenses, including costs to address negative publicity, could well exceed the actual costs of containment and cleanup. As a result, a well control incident could result in substantial liabilities for us, and have a significant negative impact on our earnings, cash flows, liquidity, financial position, and stock price.

Our drilling activities require us to risk significant amounts of capital that may not be recovered.

Drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. There can be no assurance that new wells drilled by us will be productive or that we will recover all or any portion of our investment. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. The cost of drilling, completing and operating wells is often uncertain and cost overruns are common. Our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, many of which are beyond our control, including title problems, weather conditions, equipment failures or accidents, elevated pressure or irregularities in geologic formations, compliance with governmental requirements and shortages or delays in the delivery of equipment and services.

We have less control over our investments in foreign properties than we would have with respect to domestic investments, and added risk in foreign countries may affect our foreign investments.

Our international assets and operations are subject to various political, economic and other uncertainties, including, among other things, the risks of war, expropriation, nationalization, renegotiation or nullification of existing contracts, taxation policies, foreign exchange restrictions, changing political conditions, international monetary fluctuations, currency controls and foreign governmental regulations that favor or require the awarding of drilling contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. For example, the Gabonese government's oil company may seek to participate in oil and natural gas projects in a manner that could be dilutive to the interest of current license holders and the Gabonese government is under pressure from the Gabonese labor union to require companies to hire a higher percentage of Gabonese citizens. In 2016, the government of Gabon conducted an audit of our operations in Gabon, covering the years 2013 through 2014. We received the findings from this audit and responded to the audit findings in January 2017. Since providing our response, there have been changes in the Gabonese officials responsible for the audit. We are currently working with the newly appointed representatives to resolve the audit findings. While we do not anticipate that we will be subject to assessments related to this audit that have significant, if any, negative impact on our reported earnings or cash flows, we can make no assurances that this will be the case. In addition, if a dispute arises with our foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons, especially foreign oil ministries and national oil companies, to the jurisdiction of the U.S.

As discussed in Item 1. "Business – Regulatory – Gabon," customs officials have advised us that the temporary import license cannot be renewed and that the owner of the FPSO needs to obtain a permanent import license in order to continue operating in Gabon. We are working to find other forms of relief. We are also working with the owner to ensure that they meet the requirements to obtain the permanent import license; however, the Gabon government could take actions which would impede the operations of the FPSO if this is not resolved. This matter could have an adverse impact on our financial position, results of operations or cash flows.

Private ownership of oil and natural gas reserves under oil and natural gas leases in the U.S. differs distinctly from our rights in foreign reserves where the state generally retains ownership of the minerals, and in many cases participates in, the exploration and production of hydrocarbon reserves. Accordingly, operations outside the U.S. may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges.

Beginning in February 2018, Gabon will take the portion of their oil attributable to profit oil in kind rather than our continuing to market their share of production on their behalf. We anticipate that this will cause fluctuations in the timing of and realized prices for oil sales.

All of our proved reserves are related to the Etame Marin block located offshore Gabon. We have operated in Gabon since 1995 and believe we have good relations with the current Gabonese government. However, there can be no assurance that present or future administrations or governmental regulations in Gabon will not materially adversely affect our operations or cash flows.

Our operations may be adversely affected by violent acts such as from civil disturbances, terrorist acts, regime changes, cross-border violence, war, piracy, or other conflicts that may occur in regions that encompass our operations.

Violent acts resulting in loss of life, destruction of property, environmental damage and pollution occur around the world. Many incidents are driven by civil, ethnic, religious or economic strife. In addition, the number of incidents attributed to various terrorist organizations has increased significantly. We operate in regions of the world that have experienced such incidents or are in close proximity to areas where violence has occurred.

We monitor the economic and political environments of the countries in which we operate. However, we are unable to predict the occurrence of disturbances such as those noted above. In addition, we have limited ability to mitigate their impact.

Civil disturbances, terrorist acts, regime changes, war, or conflicts, or the threats thereof, could have the following results, among others:

- volatility in global crude oil prices which could negatively impact the global economy, resulting in slower economic growth rates, which could reduce demand for our products;
- negative impact on the world crude oil supply if infrastructure or transportation are disrupted, leading to further commodity price volatility;
- difficulty in attracting and retaining qualified personnel to work in areas with potential for conflict;
- inability of our personnel or supplies to enter or exit the countries where we are conducting operations;
- disruption of our operations due to evacuation of personnel;
- inability to deliver our production due to disruption or closing of transportation routes;
- reduced ability to export our production due to efforts of countries to conserve domestic resources;
- damage to or destruction of our wells, production facilities, receiving terminals or other operating assets;
- damage to or destruction of property belonging to our commodity purchasers leading to interruption of deliveries, claims of force majeure, and/or termination of commodity sales contracts, resulting in a reduction in our revenues;
- inability of our service and equipment providers to deliver items necessary for us to conduct our operations resulting in a halt or delay in our planned exploration activities, delayed development of major projects, or shut-in of producing fields;
- lack of availability of drilling rig, oilfield equipment or services if third party providers decide to exit the region;
- shutdown of a financial system, communications network, or power grid causing a disruption to our business activities; and
- capital market reassessment of risk and reduction of available capital making it more difficult for us and our partners to obtain financing for potential development projects.

Loss of property and/or interruption of our business plans resulting from civil unrest could have a significant negative impact on our earnings and cash flow. In addition, we may not have enough insurance to cover any loss of property or other claims resulting from these risks.

Cyber-attacks targeting systems and infrastructure used by the oil and natural gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development, production and financial activities. We depend on digital technology to estimate quantities of oil and natural gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and natural gas distribution systems, which are necessary to transport our production to market. A cyber-attack directed at oil and natural gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions. While we have not experienced significant cyber-attacks, there is no assurance that we will not suffer such attacks and resulting losses in the future. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-attacks.

Competitive industry conditions may negatively affect our ability to conduct operations.

The oil and natural gas industry is intensely competitive. We compete with, and may be outbid by, competitors in our attempts to acquire exploration and production rights in oil and natural gas properties. These properties include exploration prospects as well as properties with proved reserves. There is also competition for contracting for drilling equipment and the hiring of experienced personnel. Factors that affect our ability to compete in the marketplace include:

- our access to the capital necessary to drill wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain and hire the personnel necessary to properly evaluate seismic and other information relating to a property;
- our ability to retain and hire experienced personnel, especially for our engineering, geoscience and accounting departments; and;
- the location of, and our ability to access, platforms, pipelines and other facilities used to produce and transport oil and natural gas production.

Our competitors include major integrated oil companies and substantial independent energy companies, many of which possess greater financial, technological, personnel and other resources than we do. These companies may be better able to: competitively bid for and purchase oil and natural gas properties; evaluate, bid for and purchase a greater number of properties than our financial or human resources permit; continue drilling during periods of low oil and natural gas prices; contract for drilling equipment; and secure trained personnel. Our competitors may also use superior technology which we may be unable to afford or which would require costly investment by us in order to compete.

Weather, unexpected subsurface conditions and other unforeseen operating hazards may adversely impact our oil and natural gas activities.

The oil and natural gas business involves a variety of operating risks, including fire, explosions, blow-outs, pipe failure, casing collapse, abnormally pressured formations and environmental hazards such as oil spills, natural gas leaks, ruptures and discharges of toxic gases, underground migration and surface spills or mishandling of fracture fluids including chemical additives, the occurrence of any of which could result in substantial losses to us due to injury and loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations.

We maintain insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant unfavorable event not fully covered by insurance could have a material adverse effect on our financial condition, results of operations and cash flows. Furthermore, we cannot predict whether insurance will continue to be available at a reasonable cost or at all.

Significant physical effects of climate change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects.

Climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low-lying areas, disruption of our production activities because of climate-related damages to our facilities and our costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

We may not have enough insurance to cover all of the risks we face and operators of prospects in which we participate may not maintain or may fail to obtain adequate insurance.

Our business is subject to all of the operating risks normally associated with the exploration for and production, gathering, processing, and transportation of oil and natural gas, including blowouts, cratering and fire, any of which could result in damage to, or destruction of, oil and natural gas wells or formations, production facilities, and other property, as well as injury to persons. For protection against financial loss resulting from these operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/control of a well, comprehensive general liability, worker’s compensation and employer’s liability. However, our insurance coverage may not be sufficient to cover us against 100% of potential losses arising as a result of the foregoing, and for certain risks, such as political risk, nationalization, business interruption, war, terrorism, and piracy, for which we have limited or no coverage. In addition, we are not insured against all risks in all aspects of our business, such as hurricanes. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

Our reserve information represents estimates that may turn out to be incorrect if the assumptions upon which these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present values of our reserves.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating the underground accumulations of oil and natural gas that cannot be measured in an exact manner. The estimates included in this document are based on various assumptions required by the SEC, including non-escalated prices and costs and capital expenditures subsequent to December 31, 2017, and, therefore, are inherently imprecise indications of future net revenues. Actual future production, revenues, taxes, operating expenses, development expenditures and quantities of recoverable oil and natural gas reserves may vary substantially from those assumed in the estimates. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

In addition, our reserves may be subject to downward or upward revision based upon production history, results of future development, availability of funds to acquire additional reserves, prevailing oil and natural gas prices and other factors. Moreover, the calculation of the estimated present value of the future net revenue using a 10% discount rate as required by the SEC is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our reserves or the oil and natural gas industry in general. It is also possible that reserve engineers may make different estimates of reserves and future net revenues based on the same available data.

The estimated future net revenues attributable to our net proved reserves are prepared in accordance with current SEC guidelines, and are not intended to reflect the fair market value of our reserves. In accordance with the rules of the SEC, our reserve estimates are prepared using an average of beginning of month prices received for oil and natural gas for the preceding twelve months. Future reductions in prices below the average calculated for 2017 would result in the estimated quantities and present values of our reserves being reduced.

Our proved reserves are in foreign countries and are or will be subject to service contracts, production sharing contracts and other arrangements. The quantity of oil and natural gas that we will ultimately receive under these arrangements will differ based on numerous factors, including the price of oil and natural gas, production rates, production costs, cost recovery provisions and local tax and royalty regimes. Changes in many of these factors could affect the estimates of proved reserves in foreign jurisdictions.

Our results of operations, financial condition, cash flows and compliance with debt covenants could be adversely affected by changes in currency exchange rates.

We are exposed to foreign currency risk from our foreign operations. While oil sales are denominated in U.S. dollars, portions of our costs in Gabon are denominated in the local currency. A weakening U.S. dollar will have the effect of increasing costs while a strengthening U.S. dollar will have the effect of reducing operating costs. The Gabon local currency is tied to the Euro. The exchange rate between the Euro and the U.S. dollar has fluctuated widely in recent years in response to international political conditions, general economic conditions, the European sovereign debt crisis and other factors beyond our control. Our results of operations, financial condition, cash flows and compliance with debt covenants could be adversely affected by such fluctuations in currency exchange rates.

Fluctuations in currency exchange rates may negatively impact our earnings, which are subject to financial covenants under our Amended Term Loan Agreement. Failure to maintain these covenants could preclude us from borrowing under our Amended Term Loan Agreement and require us to immediately pay down any outstanding amounts under the agreement, which could affect cash flows or restrict business. As of December 31, 2017, we were in compliance with all financial covenants under our Amended Term Loan Agreement.

Acquisitions and divestitures of properties and businesses subject our company to additional risks and uncertainties. We may be unable to integrate successfully the operations of any acquisitions with our operations, and we may not realize all the anticipated benefits of any future acquisitions. Any sales or divestments of properties we make may result in certain liabilities that we are required to retain under the terms of such sale or divestment.

Failure to successfully exploit any acquisitions we engage in could adversely affect our financial condition and results of operations. Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions.

In the case of sales or divestitures of our properties, we may become exposed to future liabilities that arise under the terms of those sales or divestitures. Under such terms, sellers typically are required to retain certain liabilities for matters with respect to their sold properties. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

Properties that we buy may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities, which could result in material liabilities and adversely affect our financial condition.

One of our growth strategies is to capitalize on opportunistic acquisitions of oil and natural gas reserves. Any future acquisition will require an assessment of recoverable reserves, title, future oil and natural gas prices, operating costs, potential environmental hazards, potential tax and employer liabilities, and other liabilities and similar factors. Ordinarily, our review efforts are focused on the higher valued properties and are inherently incomplete because it generally is not feasible to review in depth every potential liability on each individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and potential problems, such as ground water contamination and other environmental conditions and deficiencies in the mechanical integrity of equipment are not necessarily observable even when an inspection is undertaken. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition.

Additional potential risks related to acquisitions include, among other things:

- incorrect assumptions regarding the reserves, future production and revenues, or future operating or development costs with respect to the acquired properties, as well as future prices of oil and natural gas;
- decreased liquidity as a result of using a significant portion of our cash from operations or borrowing capacity to finance acquisitions;
- significant increases in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- an increase in our costs or a decrease in our revenues associated with any claims or disputes with governments or other interest owners;
- the risk that oil and natural gas reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- difficulties in the assimilation of the assets and operations of the acquired business, especially if the assets acquired are in a new business segment or geographic area;
- the diversion of management's attention from other business concerns;
- losses of key employees at the acquired businesses;
- operating a significantly larger combined organization and adding operations;
- the failure to realize expected profitability or growth;
- the failure to realize expected synergies and cost savings; and
- coordinating or consolidating corporate and administrative functions.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly.

We have been, and in the future may become, involved in legal proceedings with governmental and private litigants, and, as a result, may incur substantial costs in connection with those proceedings.

Our business subjects us to liability risks from litigation or government actions. From time to time we may be a defendant or plaintiff in various lawsuits. The nature of our operations exposes us to further possible litigation claims in the future. There is risk that any matter in litigation could be decided unfavorably against us regardless of our belief, opinion, and position, which could have a material adverse effect on our financial condition, results of operations, and cash flow. Litigation can be very costly, and the costs associated with defending litigation could also have a material adverse effect on our net income, net cash flows and financial condition. Adverse litigation decisions or rulings may also damage our business reputation.

Often, our operations are conducted through joint ventures over which we may have limited influence and control. Private litigation or government proceedings brought against us could also result in significant delays in our operations.

Compliance with environmental and other government regulations could be costly and could negatively impact production.

The laws and regulations of the U.S., Gabon, and Equatorial Guinea regulate our current business. These laws and regulations may require that we obtain permits for our development activities, limit or prohibit drilling activities in certain protected or sensitive areas, or restrict the substances that can be released in connection with our operations. Our operations could result in liability for personal injuries, property damage, natural resource damages, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. Failure to comply with environmental laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties and the issuance of orders enjoining operations. In addition, we could be liable for environmental damages caused by, among others, previous property owners or operators of properties that we purchase or lease. Some environmental laws provide for joint and several strict liabilities for remediation of releases of hazardous substances, rendering a person liable for environmental damage without regard to negligence or fault on the part of such person. As a result, we may incur substantial liabilities to third parties or governmental entities and may be required to incur substantial remediation costs. We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change and greenhouse gases and use of hydraulic fracturing fluids, resulting in increased operating costs. As a result, substantial liabilities to third parties or governmental entities may be incurred, the payment of which could have a material adverse effect on our financial condition, results of operations and liquidity. Additionally, more stringent GHG regulation could impact demand for oil and natural gas.

These laws and governmental regulations, which cover matters including drilling operations, taxation and environmental protection, may be changed from time to time in response to economic or political conditions and could have a significant impact on our operating costs, as well as the oil and natural gas industry in general. While we believe that we are currently in compliance with environmental laws and regulations applicable to our operations, no assurances can be given that we will be able to continue to comply with such environmental laws and regulations without incurring substantial costs.

If our assumptions underlying accruals for abandonment costs are too low, we could be required to expend greater amounts than expected.

Almost all of our properties which have future abandonment obligations are located offshore. The costs to abandon offshore wells may be substantial. For financial accounting purposes, we record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and capitalize the related costs as part of the carrying amount of the long-lived assets. The estimated liability is reflected in the "Asset retirement obligation" line item of the consolidated balance sheets.

As part of the Etame field production license, we are subject to an agreed upon cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. Based upon the most recent abandonment study completed in January 2016, the abandonment cost estimate used for this purpose is approximately $61.1 million ($19.0 million net to our company) on an undiscounted basis. On an annual basis over the remaining life of the production license, we must fund a portion of these estimated abandonment costs. See "Item 1. Business – Segment and Geographic Information –Gabon Segment—Etame Marin Block—Abandonment," for further information. Future changes to the anticipated abandonment cost estimates could change our asset retirement obligations and increase the amount of future abandonment funding payments we are obligated to make.

We operate in international jurisdictions, and we could be adversely affected by violations of the U.S. Foreign Corrupt Practices Act and similar worldwide anti-corruption laws.

The U.S. Foreign Corrupt Practices Act and similar worldwide anti-corruption laws generally prohibit companies and their intermediaries from making improper payments to government and other officials for the purpose of obtaining or retaining business. Our internal policies mandate compliance with these anti-corruption laws. Despite our training and compliance programs, we cannot be assured that our internal control policies and procedures will always protect us from acts of corruption committed by our employees or agents. Any additional expansion outside the U.S., including in developing countries, could increase the risk of such violations in the future. Violations of these laws, or allegations of such violations, could disrupt our business and result in a material adverse effect on our financial condition, results of operations and cash flows.

We may incur a significant penalty for failing to drill all the commitment wells under our production sharing contract in Angola.

In November 2006, we signed a production sharing contract for Block 5 offshore Angola. Under a production sharing agreement ("PSA"), we and the other participating interest owner, Sonangol P&P, were obligated to perform exploration activities that included specified seismic activities and drilling a specified number of wells during each of the exploration phases under the PSA. The specified seismic activities were completed, and one well, the Kindele #1 well, was drilled in 2015. The PSA provides a stipulated payment of $10.0 million for each exploration well for which a drilling obligation remains under the terms of the PSA, of which our participating interest share would be $5.0 million per well. We are currently engaged in discussions with newly appointed representatives from Sonangol E.P. regarding this potential payment and other possible solutions and believe that the ultimate amount paid will be substantially less than the accrued amount.

Due to the uncertainties as to the ultimate outcome, we have reflected an accrual of $15.0 million for a potential payment as of December 31, 2017 and 2016, which represents what we believe to be the maximum potential amount attributable to our interest under the PSA. However, an unfavorable result on the resolution of the ultimate amount of the penalty could have a material adverse effect on our financial position, results of operations, or cash flows.

During 2016 and 2017, we were not in compliance with the New York Stock Exchange's average minimum market capitalization and minimum share price requirements, and have been at risk of the NYSE delisting our common stock, which could materially impair the liquidity and value of our common stock.

Our common stock is currently listed on the NYSE. On April 6 and June 28, 2017, we received notices from the NYSE that we were not in compliance with a provision of the NYSE’s continued listing standards that require the average closing price of our common stock to be at least $1.00 per share over a consecutive 30-trading-day period. The 30 trading-day average closing price of the Company’s common stock for these notices had been $0.99 per share. In addition, we received a notification from the NYSE on November 30, 2016 that our market capitalization had fallen below the NYSE’s continued listing standard because our average market capitalization had fallen below $50 million over a trailing 30 trading-day period and our last reported stockholders’ equity was less than $50 million. This notice from the NYSE does not affect our business operations or trigger any default or other violation of our debt or other material obligations.

On February 1, 2017, we announced that the NYSE had accepted our plan for compliance for continued listing, which extends 18 months through May 2018. As a result, our common stock will continue to be listed on the NYSE, subject to quarterly reviews by the NYSE's Listing and Compliance Committee to ensure our progress toward our plan to restore compliance with the continued listing standards.

If we are ultimately unable to regain compliance, the NYSE will commence suspension and delisting procedures. In the event that our common stock price remains below the $1.00 per share threshold and falls to a point where the NYSE considers the stock price to be "abnormally low," the NYSE has the discretion to begin delisting procedures immediately. There is no formal definition of "abnormally low" in the NYSE rules.

A delisting of our common stock could negatively impact us by, among other things, reducing the liquidity and market price of our common stock, reducing the number of investors willing to hold or acquire our common stock, and limiting our ability to issue additional securities or obtain additional financing in the future.

There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm our business may occur and not be detected.

Our management, including our Chief Executive Officer and Principal Financial Officer, do not expect that our internal controls and disclosure controls will prevent all possible error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, an evaluation of controls can only provide reasonable assurance that all material control issues and instances of fraud, if any, in our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Further, controls can be circumvented by the individual acts of some persons or by collusion of two or more persons. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. A failure of our controls and procedures to detect error or fraud could seriously harm our business and results of operations.

Our business could suffer if we lose the services of, or fail to attract, key personnel.

We are highly dependent upon the efforts of our senior management and other key employees. The loss of the services of our chief executive officer and chief financial officer, as well as any loss of the services of one or more other members of our senior management, could delay or prevent the achievement of our objectives. We do not maintain any "key-man" insurance policies on any of our senior management, and do not intend to obtain such insurance. In addition, due to the specialized nature of our business, we are highly dependent upon our ability to attract and retain qualified personnel with extensive experience and expertise in evaluating and analyzing drilling prospects and producing oil and natural gas from proved properties and maximizing production from oil and natural gas properties. There is competition for qualified personnel in the areas of our activities, and we may be unsuccessful in attracting and retaining these personnel.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The location and general character of our principal oil and natural gas assets, production facilities, and other important physical properties have been described by segment under Item 1. “Business.” Information about oil and natural gas reserves, including the basis for their estimation, is discussed in Item 1. “Business.”

Item 3. Legal Proceedings

We are subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. It is management’s opinion that all claims and litigation we are currently involved in are not likely to have a material adverse effect on our consolidated financial position, cash flows or results of operations.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

GENERAL

Our common stock is traded on the New York Stock Exchange under the symbol EGY. The following table sets forth the range of high and low sales prices of the common stock for the periods indicated.

Period	High	Low
2017		
First Quarter	$ 1.30	$ 0.81
Second Quarter	1.14	0.85
Third Quarter	0.94	0.68
Fourth Quarter	0.94	0.70
2016		
First Quarter	$ 1.69	$ 0.87
Second Quarter	1.26	0.76
Third Quarter	1.10	0.79
Fourth Quarter	1.26	0.71

On February 28, 2018, the last reported sale price of the common stock on the New York Stock Exchange was $0.86 per share.

As of February 28, 2018, based upon information received from our transfer agent and brokers and nominees, there were approximately 44 holders of record of VAALCO common stock. This number does not include beneficial or other owners for whom common stock may be held in “street” names.

Dividends

We have not paid cash dividends and do not anticipate paying cash dividends on the common stock in the foreseeable future.

Performance Graph

The following graph compares the annual percentage change in our cumulative total stockholder return on common shares with the cumulative total return of the S&P 500 Index and the SPDR S&P Oil & Gas Exploration and Production Index. The graph assumes $100 was invested on December 31, 2012 in our common stock and in each index, and that all dividends are reinvested. Stockholder returns over the indicated period may not be indicative of future stockholder returns.

	2012	2013	2014	2015	2016	2017
SPDR S&P Oil & Gas Exploration and Production	$ 100	$ 127	$ 88	$ 56	$ 77	$ 69
S&P 500 Composite	$ 100	$ 130	$ 145	$ 143	$ 157	$ 188
VAALCO Energy, Inc.	$ 100	$ 80	$ 53	$ 18	$ 12	$ 8

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2017 regarding the number of shares of common stock that may be issued under our compensation plans. Please refer to Note 12 to the Financial Statements for additional information on stock-based compensation.

Plan Category	Number of security to be issued upon exercise of outstanding options, warrants, and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issues under equity compensation plans (excluding securities reflected in the first column)
Equity compensation plans approved by	2,365,175	$ 1.73	2,404,442

security holders				
Equity compensation plans not approved by security holders	231,706		2.28	—
Total	2,596,881	$	1.77	2,404,442

Issuer Purchases of Equity Securities for Year Ended December 31, 2017

During 2017, we acquired 26,000 shares to satisfy tax withholding obligations related to stock option exercises.

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Item 6. Selected Financial Data

The following table sets forth, as of the dates and for the periods indicated, selected financial information. The financial information for each of the five years ended December 31, 2017, 2016, 2015, 2014 and 2013 has been derived from the Financial Statements filed in the Annual Report on Form 10-K for each year. The information should be read in conjunction with "Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Financial Statements and Notes thereto. The following information is not necessarily indicative of future results.

	Years Ended December 31,							
	2017	2016		2015		2014		2013
(In thousands, except per share amounts)								
Total revenues	$ 77,025	$ 59,784	(1)	$ 80,445	(1)	$ 127,691	(1)	$ 169,277
Income (loss) from continuing operations	10,272	(18,267)	(2)	(120,554)	(2)	(73,753)	(2)	46,094
Basic income (loss) from continuing operation per share attributable to common shareholders	0.17	(0.31)		(2.07)		(1.29)		0.80
Diluted income (loss) from continuing operations per share attributable to common shareholders	0.17	(0.31)		(2.07)		(1.29)		0.79
Net property, plant and equipment	23,221	28,019		33,357	(3)	93,479	(3)	126,984
Total assets	79,633	81,032		123,958	(3)	248,849	(3)	308,167
Total long-term liabilities	22,756	25,836		31,166		29,846		11,464

(1)The decrease in total revenues is tied to the decrease in oil and natural gas prices that began in the second half of 2014 and continued through 2016. See Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations below for discussion of how price decreases and sales volume increases impacted revenues.

(2)Income (losses) from continuing operations in 2016 was primarily impacted by decreased revenues due to prevailing low oil and natural gas prices. Income (losses) from continuing operations in 2014 and 2015 were primarily impacted by decreased revenues and oil and natural gas property impairments.

(3)Net property, plant and equipment and Total assets decreased substantially in 2014 and 2015 due to impairments. See Note 6 to the Financial Statements for discussion of impairments.

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

INTRODUCTION

VAALCO is a Houston, Texas based independent energy company engaged in the acquisition, exploration, development and production of crude oil. As operator, we have production operations and conduct exploration activities in Gabon, West Africa. We have opportunities to participate in development and exploration activities as a non-operator in Equatorial Guinea, West Africa. As discussed further in Note 5 to the Financial Statements, we have discontinued operations associated with our activities in Angola, West Africa, and in April 2017 we completed the sale of our interests in Montana.

A significant component of our results of operations is dependent upon the difference between prices received for our offshore Gabon oil production and the costs to find and produce such oil. Oil and natural gas prices have been volatile and subject to fluctuations based on a number of factors beyond our control. Beginning in the third quarter of 2014, the prices for oil and natural gas began a dramatic decline which continued through 2015 and into 2016. During this period, we scaled back our global operations, divested non-core assets, amended our credit agreement and focused on reducing costs and maximizing our cash flows. Current prices, while higher than those in early 2016, are significantly less than they were in the several years prior to mid-2014. A decline in oil and natural gas prices and a sustained period of oil and natural gas prices at depressed levels could have a material adverse effect on our financial condition.

CURRENT DEVELOPMENTS

During 2016, the global oil supply continued to outpace demand, having a dampening effect on the recovery of realized crude oil prices. While global oil supply and demand were closer to being balanced during 2017, no assurances can be made that this trend will continue. Prices for crude oil improved during the second half of 2016 (ICE Dated Brent crude oil prices increased from approximately $36 per Bbl in early January 2016 to approximately $55 per Bbl at the end of 2016, and fluctuated between $44 and $67 per Bbl from January 2017 through December 2017).

On June 29, 2016, we executed the Amended Term Loan Agreement with the IFC to convert $20.0 million of the revolving portion of the credit facility into a term loan with $15.0 million outstanding at that date. The Amended Term Loan Agreement also provided us with an option to borrow an additional $5.0 million in a single draw, subject to IFC approval, through March 15, 2017. On March 14, 2017, we borrowed $4.2 million under the provisions of the Amended Term Loan Agreement. Currently under the Amended Term Loan Agreement, we have $9.0 million in total debt, net of deferred financing costs, outstanding. See Note 8 to the Financial Statements and “Capital Resources and Liquidity—Liquidity—Credit Facility” below for additional details about the Amended Term Loan Agreement. There is no further ability to borrow additional sums under the Amended Term Loan Agreement.

Our common stock is currently listed on the NYSE. On April 6 and June 28, 2017, we received notices from the NYSE that we were not in compliance with a provision of the NYSE’s continued listing standards that require the average closing price of our common stock to be at least $1.00 per share over a consecutive 30-trading-day period. The 30 trading-day average closing price of the Company's common stock for these notices had been $0.99 per share. In addition, we received a notification from the NYSE on November 30, 2016 that our market capitalization had fallen below the NYSE's continued listing standard because our average market capitalization had fallen below $50 million over a trailing 30 trading-day period and our last reported stockholders' equity was less than $50 million. This notice from the NYSE does not affect our business operations or trigger any default or other violation of our debt or other material obligations. We have until May 30, 2018 to regain compliance with the minimum market capitalization rule. We are evaluating options to either regain compliance with these rules or list on a different exchange.

DISCONTINUED OPERATIONS-ANGOLA

In November 2006, we signed a production sharing contract for Block 5 offshore Angola ("PSA"). The four year primary term, referred to as the Initial Exploration Phase ("IEP"), with an optional three year extension, awarded us exploration rights to 1.4 million acres offshore central Angola, with a commitment to drill two exploratory wells. The IEP was extended on two occasions to run until December 1, 2014. In October 2014, we entered into the Subsequent Exploration Phase ("SEP") which extended the exploration period to November 30, 2017 and required us and the co-participating interest owner, the Angolan national oil company, Sonangol P&P, to drill two additional exploration wells. Our working interest is 40%, and it carries Sonangol P&P, for 10% of the work program. On September 30, 2016, we notified Sonangol P&P that we were withdrawing from the joint operating agreement effective October 31, 2016. On November 30, 2016, we notified the national concessionaire, Sonangol E.P., that we were withdrawing from the PSA. Further to our decision to withdraw from Angola, we have closed our office in Angola and do not intend to conduct future activities in Angola. As a result of this strategic shift, the Angola segment has been classified as discontinued operations in the Financial Statements for all periods presented.

Drilling Obligation

Under the PSA, we and the other participating interest owner, Sonangol P&P, were obligated to perform exploration activities that included specified seismic activities and drilling a specified number of wells during each of the exploration phases under the PSA. The specified seismic activities were completed, and one well, the Kindele #1 well, was drilled in 2015. The PSA provides a stipulated payment of $10.0 million for each exploration well for which a drilling obligation remains under the terms of the PSA, of which our participating interest share would be $5.0 million per well. We have reflected an accrual of $15.0 million for a potential payment as of December 31, 2017 and 2016, which represents what we believe to be the maximum potential amount attributable to our interest under the PSA. However, we are currently engaged in discussions with newly appointed representatives from Sonangol E.P. regarding this potential payment and other possible solutions and believe that the ultimate amount paid will be substantially less than the accrued amount.

Other Matters – Partner Receivable

The government-assigned working interest partner was delinquent in paying their share of the costs several times in 2009 and was removed from the production sharing contract in 2010 by a governmental decree. Efforts to collect from the defaulted partner were abandoned in 2012. The available 40% working interest in Block 5, offshore Angola was assigned to Sonangol P&P effective on January 1, 2014. We invoiced Sonangol P&P for the unpaid delinquent amounts from the defaulted partner plus the amounts incurred during the period prior to assignment of the working interest totaling $7.6 million plus interest in April 2014. Because this amount was not paid and Sonangol P&P was slow in paying monthly cash call invoices since their assignment, we placed Sonangol P&P in default in the first quarter of 2015.

On March 14, 2016, we received a $19.0 million payment from Sonangol P&P for the full amount owed us as of December 31, 2015, including the $7.6 million of pre-assignment costs and default interest of $3.2 million. The $7.6 million recovery, default interest of $3.2 million and income tax is included in Loss from discontinued operations in the consolidated statements of operations for the year ended December 31, 2016.

CAPITAL RESOURCES AND LIQUIDITY

Cash Flows

Our cash flows for the years 2017, 2016 and 2015 are as follows:

	Year Ended December 31,			Increase (Decrease) in the Year	
				2017 Over (Under)	2016 Over (Under)
	2017	2016	2015	2016	2015
	(in thousands)				
Net cash provided by (used in) operating activities before change in operating assets and liabilities	$ 19,312	$ (6,470)	$ 8,021	$ 25,782	$ (14,491)
Net change in operating assets and liabilities	(8,230)	(9,268)	33,513	1,038	(42,781)
Net cash provided by (used in) continuing operating activities	11,082	(15,738)	41,534	26,820	(57,272)
Net cash provided by (used in) discontinued operating activities	(4,423)	12,286	(2,659)	(16,709)	14,945
Net cash provided by (used in) operating activities	6,659	(3,452)	38,875	10,111	(42,327)
Net cash used in continuing investing activities	(1,649)	(1,287)	(62,133)	(362)	60,846
Net cash used in discontinued investing activities	—	—	(20,877)	—	20,877
Net cash used in investing activities	(1,649)	(1,287)	(83,010)	(362)	81,723
Net cash provided by (used in) financing activities	(5,815)	(144)	441	(5,671)	(585)
Net change in cash and cash equivalents	$ (805)	$ (4,883)	$ (43,694)	$ 4,078	$ 38,811

The increase in net cash provided by our operating activities for 2017 compared to 2016 was primarily related to a $25.8 million increase in cash generated by continuing operations before change in operating assets and liabilities which in large part was the result of higher 2017 crude oil prices and lower operating costs and expenses. Net cash provided by our operating assets and liabilities increased by $1.0 million from 2016 to 2017. This overall improvement was offset by a reduction in cash generated by our discontinued operation from 2016 to 2017 of $16.7 million. The decrease in cash generated by discontinued operations was the result of a benefit received in 2016 of $19.0 million from our Angolan joint interest partner in payment of partner receivables. Net cash provided by operations decreased by $42.3 million between 2015 and 2016. Working capital changes contributed to $42.8 million of the decrease in net cash provided by operations between 2015 and 2016.

Property and equipment expenditures have historically been our most significant use of cash in investing activities. These expenditures were significantly lower in 2016 and 2017. No drilling activities were conducted during these two years as we conserved cash during the recent period of low crude oil prices. For 2017, the cash basis expenditures of $1.8 million for property and equipment was primarily related to equipment purchases. During 2016, these expenditures on a cash basis (including expenditures attributable to discontinued operations) were $8.7 million compared to $88.9 million in 2015. These cash property and equipment expenditures are included in capital expenditures. See “—Capital Expenditures” below for further discussion.

There were no other significant investing activities in 2017. For 2016, other significant investing activities included $5.7 million for the November 2016 acquisition of Sojitz’ interest in the Etame Marin block and $2.9 million to purchase oil puts used to mitigate the potential impact of price declines in 2016 and 2017, as discussed further in Note 10 to the Financial Statements. In addition, restricted cash inflows of $15.2 million in 2016 are primarily a result of us withdrawing from the joint operating agreement for Block 5 offshore Angola. Under the production sharing agreement for Block 5, we and our working interest partner, Sonangol P&P, were obligated to perform exploration activities in Angola. Prior to the September 30, 2016 quarterly reporting period, we classified the $15.0 million commitment for drilling these wells as long term restricted cash on our balance sheet. As a result of our decision to terminate the contract, we are no longer reflecting the $15.0 million as restricted cash. Restricted cash decreased by $5.5 million in 2015 because one commitment well, the Kindele #1, was drilled in Angola.

With respect to cash flows related to financing activities, for 2017, we had cash increases from $4.2 million of borrowings and cash decreases from $10.0 million of debt repayments under the Amended Term Loan Agreement. There were no significant financing activities in 2016. Net cash provided by financing activities included $0.4 million related to stock option exercises in 2015.

Capital Expenditures

At December 31, 2017, we had no material commitments for capital expenditures to be made in future years. However, we may drill two or three development wells in 2018, subject to partner and government approval. We currently have no availability for additional borrowings under our Amended Term Loan Agreement. We expect any capital expenditures made during 2018 will be funded by cash on hand, cash flow from operations and cash raised from debt and/or equity issuances.

During 2017, we had accrual basis capital expenditures attributable to continuing operations of $1.7 million compared to $(4.1) million and $66.4 million accrual basis capital expenditures in 2016 and 2015, respectively. The difference between capital expenditures and the property and equipment expenditures reported in the consolidated statements of cash flows is attributable to changes in accruals for costs incurred but not yet invoiced or paid on the report dates. Capital Expenditures in 2017 and 2016 were mainly for equipment and enhancements. Capital Expenditures in 2015 were primarily associated with the drilling of five development wells offshore Gabon.

In early January 2016, we determined that additional development drilling was uneconomic at the then prevailing commodity prices and initiated the demobilization of a drilling rig we had under contract as we determined we would not drill any wells on the Etame Marin block in 2016. In June 2016, we reached an agreement with the drilling contractor to pay $5.1 million net to VAALCO's interest for unused rig days under the contract. We paid this amount, including the demobilization charges, in seven equal monthly installments beginning in July 2016 and ending in January 2017.

Contractual Obligations

The table below provides aggregated information on our net share of cash obligations and commitments at December 31, 2017:

	2018	2019	2020	2021	2022	Thereafter	Total
IFC credit facility(1)	$ 6,666	$ 2,500	$ —	$ —	$ —	$ —	$ 9,166
Operating leases(2)	11,895	10,126	7,369	—	—	—	29,390
Abandonment funding(3)	2,298	1,642	1,642	1,641	—	—	7,223
Total cash obligations	$ 20,859	$ 14,268	$ 9,011	$ 1,641	$ —	$ —	$ 45,779

(1) See discussion of the Amended Term Loan Agreement above under "—Credit Facility". Interest estimated to be paid on borrowings under the Amended Term Loan Agreement in each of 2018 through 2019 is $0.4 million and $0.1 million.

(2) Included in these figures is our net share of charter payments for the FPSO used on the Etame Marin block. See "FPSO Charter" in Note 9 to the Financial Statements for further information.

(3) See "Abandonment funding" in Note 9 to the Financial Statements for further information.

We have an agreed cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. Based upon the abandonment study completed in January 2016, the abandonment cost estimate used for this purpose is approximately $61.1 million ($19.0 million net to VAALCO) on an undiscounted basis. The obligation for abandonment of the Gabon offshore facilities is included in the "Asset retirement obligations" line item on our consolidated balance sheet. Through December 31, 2017, $34.8 million ($10.8 million net to VAALCO) on an undiscounted basis has been funded. This cash funding is reflected under "Other noncurrent assets" in the "Abandonment funding" line item of our consolidated balance sheet. The next funding is expected to be $7.4 million ($2.3 million net to VAALCO) and paid in December 2018; however, future changes to the anticipated abandonment cost estimate could change our asset retirement obligation and the amount of future abandonment funding payments.

Regulatory and Joint Interest Audits

We are subject to periodic routine audits by various government agencies in Gabon, including audits of our petroleum cost account, customs, taxes and other operational matters, as well as audits by other members of the contractor group under our joint operating agreements.

As of December 31, 2017, we had accrued $1.8 million net to VAALCO in “Accrued liabilities and other” on our consolidated balance sheet for these various audits by governmental agencies in Gabon. See Note 9 to the Financial Statements for further discussion.

Capital Resources

Credit Facility

Historically, our primary sources of capital have been cash flows from operating activities, borrowings under the credit facility with the IFC and cash balances on hand. The $9.2 million in principal outstanding under our Amended Term Loan Agreement matures in June 2019, and requires quarterly principal and interest payments on the amounts currently outstanding continuing through June 30, 2019. Interest accrues on the unpaid balance at the per annum rate of LIBOR plus 5.75%. The current portion of the outstanding debt was $6.7 million as of December 31, 2017. Our repayment obligations under the Amended Term Loan Agreement require us to pay installments of principal totaling $6.7 million in 2018 and $2.5 million in 2019. We may make no further borrowings under the terms of the Amended Term Loan Agreement.

The indebtedness under our Amended Term Loan Agreement is secured by the assets of our Gabon subsidiary, VAALCO Gabon S.A. and is guaranteed by VAALCO Energy, Inc., as the parent company.

The Amended Term Loan Agreement contains a number of restrictive covenants that impose significant operating and financial restrictions on us. These covenants restrict our ability to engage in certain actions, including potentially limiting our ability to sell assets, make future borrowings or incur other additional indebtedness. Our ability to meet our quarter-end net debt to EBITDAX ratio and our debt service coverage ratio can be affected by events beyond our control, including changes in commodity prices.

Under the Amended Term Loan Agreement, quarter-end net debt to EBITDAX (as defined in the loan agreement) must be no more than 3.0 to 1.0. Additionally, our debt service coverage ratio must be greater than 1.2 to 1.0 at semi-annual review period. Forecasting our compliance with these and other financial covenants in future periods is inherently uncertain. Factors that could impact our quarter-end financial covenants in future periods include future realized prices for sales of oil and natural gas, estimated future production, returns generated by our capital program, and future interest costs, among others. We are in compliance with all financial covenants as of December 31, 2017, and we expect to be in compliance with these covenants through maturity. However, there can be no assurance that we will be able to comply with these financial covenants in future periods. In addition, if we receive any waivers or amendments to our Amended Term Loan Agreement, the lender may impose additional operating and financial restrictions on us.

A breach of the covenants under our Amended Term Loan Agreement could result in an event of default under the agreement. Such a default may allow the lender to accelerate payment of the indebtedness under the agreement and may result in the acceleration of any other indebtedness to which a cross-acceleration or cross-default provision applies. Furthermore, if we were unable to repay the amounts due and payable under the loan agreement, the lender could proceed against the collateral that we granted to it to secure that indebtedness.

Cash on Hand

At December 31, 2017, we had unrestricted cash of $19.7 million. As operator of the Etame Marin and Mutamba Iroru blocks in Gabon, we enter into project related activities on behalf of our working interest partners. We generally obtain advances from partners prior to significant funding commitments. Our cash on hand will be utilized, along with cash generated from operations, to fund our operations for the foreseeable future.

We currently sell our crude oil production from Gabon under a term contract that ends in January 2019. Pricing under the contract is based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

Liquidity

As discussed above, our revenues, cash flow, profitability, oil and gas reserve values and future rates of growth are substantially dependent upon prevailing prices for oil. Our ability to borrow funds and to obtain additional capital on attractive terms is also substantially dependent on oil prices. After a period of low commodity prices, oil and gas prices have stabilized at levels which are currently adequate to generate cash from operating activities for our continuing operations. In addition to the impact of oil and gas prices on our access to capital markets, the availability of capital resources on attractive terms may be limited due to the geographic location of our primary producing assets. As discussed above, we may drill two or three development wells in 2018. Any drilling program we enter into would require approval of our partners and the government of Gabon. We expect any capital expenditures made during 2018 will be funded by cash on hand, cash flow from operations and cash raised from debt and/or equity issuances. We believe that at current prices, cash generated from continuing operations, together with cash on hand at December 31, 2017, are adequate to support our operations and cash requirements during 2018 and through March 31, 2019.

At December 31, 2017, we had 3.0 MMBOE of proved reserves, all of which are related to the Etame Marin block offshore Gabon. The current term for exploitation of the reserves in the Etame Marin block ends in June 2021, and as discussed in Item 1. “Business – Strategy” above, we are focused on extending the license for the block, and this could favorably improve our long-term liquidity. Except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, our estimated net proved reserves will generally decline as reserves are produced. While both short-term and long-term liquidity are impacted by crude oil prices, our long-term liquidity also depends upon our ability to find, develop or acquire additional oil and gas reserves that are economically recoverable.

OFF BALANCE SHEET ARRANGEMENTS

In connection with the charter of the FPSO (see "FPSO charter" in Note 9 to the Financial Statements), we, as operator of the Etame Marin block, guaranteed all of the lease payments under the charter through its contract term, which expires in September 2020. At our election, the charter may be extended for two one-year periods beyond September 2020. We obtained guarantees from each of our partners for their respective shares of the payments. Our net share of the charter payment is 31.1%, or approximately $9.7 million per year. Although we believe the need for performance under the charter guarantee is remote, we recorded a liability of $0.5 million and $0.7 million as of December 31, 2017 and 2016, respectively, representing the guarantee's fair value. The guarantee of the offshore Gabon FPSO lease has $85.2 million in remaining gross minimum obligations for the total amount of charter payments at December 31, 2017. There have been no other material off-balance sheet arrangements entered into since December 31, 2017.

RESULTS OF OPERATIONS

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

We reported net income for the year ended December 31, 2017 of $9.7 million, compared to a net loss of $26.6 million for the same period of 2016. These amounts of income (loss) were inclusive of our loss from discontinued operations for the year ended December

31, 2017 of $0.6 million, and loss from discontinued operations for the year ended December 31, 2016 of $8.3 million. Further discussion of results by significant line item follows.

Oil and natural gas revenues increased $17.2 million, or approximately 28.8%, during the year ended December 31, 2017 compared to the same period of 2016. A substantial portion of the increase in revenue is related to higher realized oil prices as well as higher revenue attributable to the Sojitz acquisition. This was offset in part by an overall decrease in sales volumes. Volumes in 2017 were adversely impacted because the last lifting in 2017 was not completed until January 1, 2018. Net revenues of $6.5 million associated with net volumes delivered to the buyer on January 1, 2018 of 95,525 barrels will be reported as revenue in 2018.

The revenue changes between the years ended December 31, 2017 and 2016 identified as related to changes in price or volume are shown in the table below:

(in thousands)	
Price	$ 17,716
Volume	(2,850)
Other	2,375
	$ 17,241

The table below shows net production, sales volumes and realized prices for both years.

	Year Ended December 31, 2017	Year Ended December 31, 2016
Gabon net oil production (MBbls)	1,518	1,515
International net oil sales (MBbls)	1,423	1,485
U.S. net oil sales (MBbls)	—	3
Net oil sales (MBbls)	1,423	1,488
Net natural gas sales (MMcf)	—	124
Net oil equivalents (MBOE)	1,423	1,509
Average realized oil price ($/Bbl)	$ 52.58	$ 40.13
Average realized natural gas price ($/Mcf)	—	1.95
Weighted average realized price ($/BOE)	52.58	39.62
Average Dated Brent spot* ($/Bbl)	54.10	43.67

*Average of daily Dated Brent spot prices posted on the U.S. Energy Information Administration website.

Crude oil sales are a function of the number and size of crude oil liftings in each quarter from the FPSO, and thus crude oil sales do not always coincide with volumes produced in any given quarter. We made twelve liftings for the years ended December 31, 2017 and 2016. However, volumes for the last lifting in 2017 were low as they exclude the volumes lifted on January 1, 2018 when the lifting operation was completed. Our share of oil inventory aboard the FPSO, excluding royalty barrels, was approximately 122,076 and 46,700 barrels at December 31, 2017 and 2016, respectively.

Production expenses increased $2.1 million, or approximately 5.6%, in the year ended December 31, 2017 compared to the same period of 2016, primarily as a result of our increased ownership in the Etame Marin block of Gabon after the November 2016 Sojitz acquisition, costs related to the planned maintenance turnaround, asset integrity work performed during the planned turnaround, costs associated with certain regulatory requirements in Gabon, custom fees and FPSO cost escalation.

Depreciation, depletion and amortization (“DD&A”) decreased $0.5 million, or approximately 6.8%, in the year ended December 31, 2017 compared to the same period of 2016 due to the favorable impact of depleting our costs over a higher reserve base as a result of improvements in estimated reserves identified at December 31, 2016 and at December 31, 2017 as well as lower lifting volumes.

General and administrative expenses increased $0.8 million, or approximately 8.5% in the year ended December 31, 2017 compared to the same period of 2016. The increase was primarily related to higher legal fees and accounting and auditing costs offset by lower personnel costs. Personnel costs were lower in 2017 as a result of lower wages and employee benefits offset by higher stock-based compensation as 2016 included the benefit related to employee forfeitures.

Bad debt expense and other for the year ended December 31, 2017 and 2016 related to Value Added Tax (“VAT”) which the government of Gabon is required to reimburse but has not yet paid.

Other operating expenses for the year ended December 31, 2016 included $1.0 million accrued for certain unpaid payroll taxes in Gabon which were not paid pertaining to labor provided to us over a number of years by a third-party contractor and $7.9 million, net to VAALCO, of expense associated with the demobilization and release of the contracted drilling rig. In June 2016, we reached an agreement with the drilling contractor to pay less than our originally estimated maximum day rate, plus demobilization costs, in seven equal monthly installments beginning in July 2016. In January 2017, we resolved the Gabon payroll tax obligation.

General and administrative related to shareholder matters for the year ended December 31, 2016 reflects offsetting insurance proceeds related to costs incurred on shareholder litigation that was settled in 2016.

Other, net for the year ended December 31, 2017 consists primarily of $2.6 million related to the reversal of accruals for liabilities we are no longer obligated to pay as well as $0.5 million in foreign currency gains. These gains were offset by $1.0 million of losses on derivative instruments (see Note 10 to the Financial Statements). In 2016 Other, net included $1.7 million in derivative instrument losses. Foreign currency losses were minimal in 2016.

Interest expense for the year ended December 31, 2017 and 2016 relates to borrowings under our Amended Term Loan Agreement as discussed in Note 8 to the Financial Statements.

Income tax expense increased $1.1 million in the year ended December 31, 2017 compared to the same period of 2016. Income tax expense in both periods is primarily attributable to our operations in Gabon and is higher in 2017 than income tax for the comparable 2016 period primarily as a result of higher revenues. In addition, income tax expense was offset by a $1.3 million benefit from the reversal of valuation allowances on deferred tax assets attributable to Alternative Minimum Tax (“AMT”) credit carryforwards in the U.S. as a result of expected refunds of these credits under the tax legislation enacted in December 2017.

Loss from discontinued operations for the year ended December 31, 2017 is attributable to our Angola segment as discussed further in Note 5 to the Financial Statements. The loss from discontinued operations for the 2017 period is related to ongoing administrative costs. For the year ended December 31, 2016 we reported loss from discontinued operations primarily as a result of $3.1 million of income tax on financial gains and $15.0 million accrual for the potential payment of drilling obligations offset by $7.6 million of bad debt recovery and $3.2 million of collected default interest.

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

We reported a net loss for the year ended December 31, 2016 of $26.6 million compared to a net loss of $158.7 million for the same period of 2015. These losses are inclusive of losses from discontinued operations for the years ended December 31, 2016 and 2015 of $8.3 million and $38.1 million, respectively. The 2016 losses from continuing operations are primarily attributable to lower revenues resulting from lower oil prices and expenses associated with the demobilization and early release of a contracted drilling rig. The 2015 losses from continuing operations are primarily attributable to non-cash proved property impairments and decreased revenues resulting from the severe decline in oil prices that began in 2014. The write-off of suspended well costs related to the N’Gongui No. 2 well and provisions for bad debt of $2.7 million also adversely impacted 2015. Further discussion of results by significant line item follows:

Oil and natural gas revenues decreased $20.7 million during the year ended December 31, 2016 compared to the same period of 2015. Based on the average realized oil prices in the table below, the decrease in revenue is primarily related to 16% lower realized oil prices due to decreases in the Dated Brent market price which were experienced in the first half of the year and 12% lower oil sales volume due to temporarily shut-in wells, two of which were worked over and returned to production in December 2016 and January 2017.

The revenue changes between the years ended December 31, 2016 and 2015 identified as related to changes in price or volume are shown in the table below:

(in thousands)	
Price	$ (11,518)
Volume	(9,409)
Other	266
	$ (20,661)

The table below shows net production, sales volumes and realized prices for both years.

	Year Ended December 31,	
	2016	2015
Gabon net oil production (MBbls)	1,515	1,656
International net oil sales (MBbls)	1,485	1,679
U.S. net oil sales (MBbls)	3	3
Net oil sales (MBbls)	1,488	1,682
Net natural gas sales (MMcf)	124	181
Net oil equivalents (MBOE)	1,509	1,712
Average realized oil price ($/Bbl)	$ 40.13	$ 47.85
Average realized natural gas price ($/Mcf)	1.95	2.21
Weighted average realized price ($/BOE)	39.62	47.24
Average Dated Brent spot* ($/Bbl)	43.67	52.32

*Average of daily Dated Brent spot prices posted on the U.S. Energy Information Administration website.

Crude oil sales are a function of the number and size of crude oil liftings from the FPSO, and thus crude oil sales do not always coincide with volumes produced in any given period. We made 12 and 11 liftings in the years ended December 31, 2016 and 2015, respectively. Our share of oil inventory aboard the FPSO, excluding royalty barrels, was approximately 46,700 and 34,000 barrels at December 31, 2016 and 2015, respectively.

Crude oil sales are a function of the number and size of crude oil liftings from the FPSO, and thus crude oil sales do not always coincide with volumes produced in any given period. We made 12 and 11 liftings in the years ended December 31, 2016 and 2015, respectively. Our share of oil inventory aboard the FPSO, excluding royalty barrels, was approximately 46,700 and 34,000 barrels at December 31, 2016 and 2015, respectively.

Production expenses decreased $2.5 million in 2016 compared to 2015. Production expenses included workover costs to replace ESPs which were $6.8 million in 2016 and $4.2 million in 2015. The 2015 production expenses are higher because they include $1.9 million related to studies to evaluate solutions for a centralized processing facility to remove H_2S from the sour production on the block. Excluding workovers and H_2S studies, the overall decrease in production expense was $3.2 million, which reflects some success in ongoing cost cutting efforts.

Exploration expense was minimal in 2016 compared to $10.4 million in 2015. During 2015, we charged to dry hole costs $9.2 million of exploratory well costs incurred in 2012 related to the N'Gongui No. 2 discovery that had been capitalized pending the determination of proved reserves. Also in 2015, we recorded impairments of $1.3 million related to undeveloped leasehold costs associated with Poplar Dome in the U.S. The following table shows exploration expense in detail.

(in thousands)	Year Ended December 31, 2016	2015
Exploration expenses:		
Dry hole costs	$ —	$ 8,994
Unproved leasehold impairment	—	1,250
Seismic	—	61
Other	5	104
Total exploration expenses	$ 5	$ 10,409

Depreciation, depletion and amortization (“DD&A”) expenses decreased $26.1 million in 2016 compared to 2015. DD&A per BOE rates were lower in 2016 reflecting the impact of impairments in 2015, particularly the $52.1 million impairment made in the fourth quarter of 2015.

General and administrative expenses decreased $2.7 million in 2016 compared to 2015. This is primarily a result of a $3.6 million decrease in stock-based compensation expense reflecting forfeitures related to employee departures. In addition, we took steps beginning in 2015 to reduce overall general and administrative costs, with decreases realized in personnel costs, services and various other cost categories. However, the amount of overhead we were able to recover from our partners in 2016 has decreased and more than offset the benefits from reductions in personnel and other costs. Under our operating agreements the amount of overhead recoverable is larger when capital spending is higher, as it was in 2015 with the development program in Gabon and the exploratory drilling in Angola.

Impairment of proved properties is discussed in detail in Note 6 to the Financial Statements. Declining forecasted oil prices in 2015 caused us to record an impairment of $81.3 million.

Other operating loss, net in 2016 included $1.0 million accrued for certain unpaid payroll taxes in Gabon which were not paid pertaining to labor provided to us over a number of years by a third-party contractor and $7.9 million, net to VAALCO, of expense associated with the demobilization and release of the contracted drilling rig.

General and administrative related to shareholder matters for 2016 and 2015 reflects costs incurred related to shareholder litigation that was settled in 2016. For 2016, the amounts also include the offsetting insurance proceeds related to these matters.

Bad debt expense and other for both the years ended December 31, 2016 and 2015 includes bad debt expense related to VAT which the government of Gabon is required to reimburse but has not yet paid.

Other operating income (loss), net decreased by $0.8 million in 2016 compared to 2015. Both years consisted primarily of impairments of capitalized equipment inventory located in Gabon. Equipment inventory in Gabon related to Mutamba was written off because further drilling in the prospect was uneconomic, while equipment inventory related to the Etame Marin block was reduced in value due to obsolescence of some items.

Interest expense increased $1.3 million in 2016 compared to 2015 primarily due to the write-off of previously deferred financing costs in June 2016 upon conversion of our credit facility to the term loan and a decrease in capitalized interest as none of the interest expense incurred in 2016 was capitalized versus $0.8 million capitalized in 2015. See Note 8 to the Financial Statements for further discussion of our loan agreement and interest expense.

Other, net consists primarily of derivative instrument gains (losses) as discussed in Note 10 to the Financial Statements and foreign currency gains (losses).

Income tax expense decreased $5.3 million in 2016 compared to 2015. Income tax expense in both periods is primarily attributable to our operations in Gabon and is lower in 2016 than income tax for the comparable 2015 period as a result of lower revenues.

Loss from discontinued operations is attributable to our Angola segment as discussed further in Note 5 to the Financial Statements. Results for discontinued operations for the year ended December 31, 2016 were primarily as a result of $3.1 million of income tax on financial gains and $15.0 million accrual for the potential payment of drilling obligations offset by $7.6 million of bad debt recovery and $3.2 million of collected default interest. Results for 2015 were primarily attributable to dry hole costs for the Kindele #1 well, higher general and administrative expense and impairments of equipment inventory, offset by higher foreign exchange gains.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of the Financial Statements in accordance with accounting principles generally accepted in the U.S. (“GAAP”) requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the Financial Statements and the reported amounts of revenues and expenses during the respective reporting periods. Accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change, and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used. Further, in some cases, GAAP allows more than one alternative accounting method for reporting. In those cases, our reported results of operations would be different should we employ an alternative accounting method. See Note 3 to the Financial Statements for our accounting policy elections.

Successful Efforts Method of Accounting for Oil and Natural Gas Activities

We use the successful efforts method to account for our oil and natural gas activities. Management believes that this method is preferable, as we have focused on exploration activities wherein there is risk associated with future success and as such earnings are best represented by drilling results. Costs of successful wells, development dry holes and leases containing productive reserves are capitalized and amortized on a unit-of-production basis over the life of the related reserves. Other exploration costs, including dry exploration well costs, geological and geophysical expenses applicable to undeveloped leaseholds, leasehold expiration costs and delay rentals, are expensed as incurred.

The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. Cost incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) sufficient progress in assessing the reserves and the economic and operating viability of the project has been made. The status of suspended well costs is monitored continuously and reviewed quarterly. Due to the capital-intensive nature and the geographical characteristics of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination of its commercial viability.

Geological and geophysical costs are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense.

We capitalize interest, if debt is outstanding, during drilling operations in our exploration and development activities.

We review our oil and natural gas producing properties for impairment on a field-by-field basis whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment charge is recorded based on the fair value of the asset. This may occur if a field contains lower than anticipated reserves or if commodity prices fall below a level that significantly effects anticipated future cash flows on the field. The fair value measurement used in the impairment test is generally calculated with a discounted cash flow model using several Level 3 inputs which are based upon estimates, the most significant of which is the estimate of net proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas sales prices may all differ from those assumed in these estimates.

Impairment of Unproved Property

We evaluate our undeveloped oil and natural gas leases for impairment on at least a quarterly basis by considering numerous factors that could include nearby drilling results, seismic interpretations, market values of similar assets, existing contracts and future plans for exploration or development. When undeveloped oil and natural gas leases are deemed to be impaired, exploration expense is charged. Unproved property costs consist of acquisition costs related to undeveloped acreage in Equatorial Guinea. See “Item 1—Business—Segment and Geographic Information—Equatorial Guinea Segment” for further information on our exploration plans in Equatorial Guinea.

Asset Retirement Obligations (“ARO”)

We have significant obligations to remove tangible equipment and restore land or seabed at the end of oil and natural gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells, removing and disposing of all or a portion of offshore oil and natural gas platforms, and capping pipelines. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations.

A liability for ARO is recognized in the period in which the legal obligations are incurred if a reasonable estimate of fair value can be made. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with our oil and natural gas properties. We use current retirement costs to estimate the expected cash outflows for asset retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. Initial recording of the ARO liability is offset by the corresponding capitalization of asset retirement cost recorded to oil and natural gas properties. To the extent these or other assumptions change after initial recognition of the liability, the fair value estimate is revised and the recognized liability adjusted, with a corresponding adjustment made to the related asset balance or income statement, as appropriate. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is generally determined on a units-of-production basis for oil and natural gas production facilities, while accretion escalates over the lives of the assets to reach the expected settlement value.

ARO associated with retiring tangible long-lived assets is recognized as a liability in the period in which the legal obligation is incurred and becomes determinable. The liability is offset by a corresponding increase in the underlying asset. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with our oil and natural gas properties. We use current retirement costs to estimate the expected cash outflows for retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and natural gas property balance. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

NEW ACCOUNTING STANDARDS

See Note 4 to the Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk, including the effects of adverse changes in commodity prices, foreign exchange rates and interest rates as described below.

Foreign Exchange Risk

Our results of operations and financial condition are affected by currency exchange rates. While oil sales are denominated in U.S. dollars, portions of our costs in Gabon and Angola are denominated in the respective local currency and our VAT receivable in Gabon is also denominated in the Gabon local currency. A weakening U.S. dollar will have the effect of increasing costs while a strengthening U.S. dollar will have the effect of reducing costs. For our VAT receivable in Gabon, a strengthening U.S. dollar will have the effect of decreasing the value of this receivable resulting in foreign exchange losses and vice versa. The Gabon local currency is tied to the Euro. The exchange rate between the Euro and the U.S. dollar has historically fluctuated widely in response to international political conditions, general economic conditions and other factors beyond our control. The exchange rate between the Angola local currency and the U.S. dollar has fluctuated for similar reasons, with the Angola local currency devaluing in 2015 and 2016. As a result of discontinuing operations in Angola, our exposure to the Angola local currency has declined significantly.

Interest Rate Risk

The floating rate on borrowings under our Amended Term Loan Agreement exposes us to risks associated with changes in interest rates (LIBOR). At December 31, 2017 and 2016, we had $9.2 million and $15.0 million, respectively, in borrowings outstanding with the IFC. Our deferred financing costs totaled $0.2 million and $0.6 million at December 31, 2017 and 2016, respectively. Fluctuations in floating interest rates will cause our interest costs to fluctuate. During years ended December 31, 2017, 2016 and 2015, the average effective interest rate on our debt, excluding commitment fees, was 6.72%, 5.52% and 4.09%, respectively. If the balance of the debt at December 31, 2017 were to remain constant, a 1% change in market interest rates would impact our cash flow by an estimated $92,000 per year. As future quarterly payments reduce the principal of the term loan, our cash flow becomes less sensitive to fluctuations in interest rate.

Commodity Price Risk

Our major market risk exposure continues to be the prices received for our oil and natural gas production. Sales prices are primarily driven by the prevailing market prices applicable to our production. Market prices for oil and natural gas have been volatile and unpredictable in recent years, and this volatility may continue. Beginning in the third quarter of 2014, the prices for oil and natural gas began a dramatic decline which continued through the first half of 2016. Current prices remain significantly lower than they were in years prior to 2015. Sustained low oil and natural gas prices or a resumption of the decreases in oil and natural gas prices could have a material adverse effect on our financial condition, the carrying value of our proved reserves, our undeveloped leasehold interests and our ability to borrow funds and to obtain additional capital on attractive terms. If oil sales were to remain constant at the most recent annual sales volumes of 1,423 MBbls, a $5 per Bbl decrease in oil price would be expected to cause a $7.1 million decrease per year in revenues and operating income (loss) and a $6.0 million decrease per year in net income.

During the years ended December 31, 2017 and 2016, we had oil puts outstanding which were intended to be an economic hedge against declines in crude oil prices; however, they were not designated as hedges for accounting purposes. These puts had expired as of December 31, 2017, and we had no other commodity price derivatives outstanding during this period. As of and during the year ended December 31, 2015, we had no commodity price derivatives outstanding.

Item 8. Financial Statements and Supplementary Data

The information required here begins on page F-1 as described in “Item 15. Exhibits and Financial Statement Schedules—Index to Consolidated Financial Information”.

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

None.

Item 9A. Controls and Procedures

MANAGEMENT'S EVALUATION OF Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management was required to apply its judgment in evaluating and implementing possible controls and procedures. Management, including our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. Based on this evaluation, our principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2017.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management, including our Chief Executive Officer and our Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Under the supervision and with the participation of management, including our principal executive and principal financial officers, we conducted an evaluation of the effectiveness of our internal control over financial reporting using the criteria set forth in the Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework").

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

Based on the evaluation, our management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Financial Statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of Financial Statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the Financial Statements.

BDO USA, LLP, an independent registered public accounting firm, audited the effectiveness of the Company's internal control over financial reporting as of December 31, 2017, as stated in their report included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

Remediation of material weaknesses

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2016, our management concluded that there were material weaknesses in our internal control over financial reporting. In response to the identified material weaknesses at December 31, 2016, our management, with oversight from our Audit Committee, undertook the following remedial actions during 2017:

- Improved the timing of the periodic financial close, reporting process and analysis of results through the use of a detail financial close plan;
- Implemented and redesigned new controls to strengthen the review process of key financial information;
- Expanded the scope of reporting of financial data to management;
- Hired additional permanent employees for key roles in accounting and finance, which had previously been performed by professional consultants;
- Implemented training programs which included cross-training and professional training related to accounting standards and industry practices;
- Developed and implemented formal policies and procedures related to the annual physical observation of equipment inventory; and
- Implemented improved procedures related to equipment inventory record keeping.

After completing our testing of the design and operational effectiveness of these controls, our management concluded that we remediated the previously identified material weaknesses as of December 31, 2017.

Changes in internal control over financial reporting

Except for the remediation procedures detailed above for the previously identified material weaknesses, there have been no other changes in our internal control over financial reporting during the three months ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

Shareholders and Board of Directors

VAALCO Energy, Inc.

Houston, Texas

Opinion on Internal Control over Financial Reporting

We have audited VAALCO Energy, Inc.'s. (the "Company's") internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO criteria"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017 based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets of the Company and subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of operations, shareholders' equity (deficit), and cash flows for the years then ended and the related notes and financial statement schedule and our report dated March 7, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Item 9A, Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit of internal control over financial reporting in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

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

/s/ BDO USA, LLP

Houston, Texas

March 7, 2018

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information required by this item will be included in the proxy statement for our 2018 annual meeting, which will be filed with the Commission within 120 days of December 31, 2017, and which is incorporated herein by reference.

Item 11. Executive Compensation

Information required by this item will be included in the proxy statement for our 2018 annual meeting, which will be filed with the Commission within 120 days of December 31, 2017, and which is incorporated herein by reference.

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

Information required by this item under Item 403 of Regulation S-K concerning the security ownership of certain beneficial owners and management will be included in the Company's proxy statement for its 2018 annual meeting, which will be filed with the Commission within 120 days of December 31, 2017, and which is incorporated herein by reference. Please see "Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchase of Equity Securities" for information on securities that may be issued under our stock incentive plans.

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

Information required by this item will be included in the proxy statement for our 2018 annual meeting, which will be filed with the Commission within 120 days of December 31, 2017, and which is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Information required by this item will be included in the proxy statement for our 2018 annual meeting, which will be filed with the Commission within 120 days of December 31, 2017, and which is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1. The following is an index to the financial statements that are filed as part of this Form 10-K.

VAALCO ENERGY, INC. AND SUBSIDIARIES

(a) 2. Other schedules are omitted because they are not required, not applicable or the required information is included in the Financial Statements or notes thereto.

(a) 3. Exhibits:

3.1	Certificate of Incorporation as amended through May 7, 2014 (filed as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q filed on November 10, 2014, and incorporated herein by reference).
3.2	Second Amended and Restated Bylaws (filed as Exhibit 3.2 to the Company’s Current Report on Form 8-K filed on September 28, 2015, and incorporated herein by reference).
3.3	First Amendment to the Second Amended and Restated Bylaws of VAALCO Energy, Inc., dated as of December 22, 2015 (filed as Exhibit 3.1 to the Company’s Current Report on Form 8-K filed on December 23, 2015, and incorporated herein by reference).
3.4	Certificate of Elimination of Series A Junior Participating Preferred Stock of VAALCO Energy, Inc., dated as of December 22, 2015 (filed as Exhibit 3.2 to the Company’s Current Report on Form 8-K filed on December 23, 2015, and incorporated herein by reference).
10.1(a)	Exploration and Production Sharing Contract, dated July 7, 1995, between the Republic of Gabon and VAALCO Gabon (Etame), Inc.
10.2	Addendum No. 1 to Exploration and Production Sharing Contract, dated July 7, 2001, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.2 to the Company’s Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.3	Addendum No. 2 to Exploration and Production Sharing Contract, dated July 7, 2006, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.3 to the Company’s Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.4	Addendum No. 3 to Exploration and Production Sharing Contract, dated November 26, 2009, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.4 to the Company’s Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.5	Addendum No. 4 to Exploration and Production Sharing Contract, dated January 5, 2012, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.5 to the Company’s Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.6(a)	Addendum No. 5 to Exploration and Production Sharing Contract, dated April 25, 2016, between the Republic of Gabon and VAALCO Gabon (Etame), Inc.
10.7(a)	Deed of Novation of Trustee and Paying Agent Agreement, dated June 22, 2017, by and among VAALCO Gabon (Etame), Inc., VAALCO Gabon S.A. and The Bank of New York Mellon, London Branch as the Trustee and Paying Agent and the Account Bank.
10.8	Production Sharing Agreement, dated November 1, 2006, between Sonangol, E.P. and VAALCO Angola (Kwanza), Inc. (filed as Exhibit 10.8 to the Company’s Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.9	Supplemental Loan Agreement, dated June 29, 2016, between VAALCO Gabon (Etame), Inc. and International Finance Corporate (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on July 6, 2016, and incorporated herein by reference).
10.10*	VAALCO Energy, Inc. 2001 Stock Incentive Plan (filed as Exhibit 99.1 to the Company’s Registration Statement on Form S-8 filed on August 17, 2001, and incorporated herein by reference).
10.11*	VAALCO Energy, Inc. 2012 Long Term Incentive Plan (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on May 30, 2012, and incorporated herein by reference).
10.12*	VAALCO Energy, Inc. 2014 Long Term Incentive Plan (filed as Appendix A to the Company’s Definitive Proxy Statement on Schedule 14A filed on April 17, 2014, and incorporated herein by reference).
10.13*	Form of Restricted Stock Award Agreement under the VAALCO Energy, Inc. 2014 Long Term Incentive Plan (filed as Exhibit 10.20 to the Company’s Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).

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10.14*	Form of Nonstatutory Stock Option Agreement under the VAALCO Energy, Inc. 2014 Long Term Incentive Plan (filed as Exhibit 10.21 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.15*	Form of Restricted Stock Award Agreement (for Directors) under the VAALCO Energy, Inc. 2014 Long Term Incentive Plan (filed as Exhibit 10.22 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.16*	Employment Agreement between the Company and Cary Bounds (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on December 29, 2016, and incorporated herein by reference).
10.17*	Employment Agreement between the Company and Philip Patman, Jr. (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 17, 2017, and incorporated herein by reference).
10.18*	Employment Agreement, effective April 17, 2017, between VAALCO Energy, Inc. and Philip Patman, Jr. (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 18, 2017, and incorporated herein by reference)
10.19	Settlement Agreement, dated as of December 22, 2015, by and among VAALCO Energy, Inc., Group 42, Inc. Mr. Paul A. Bell, Michael Keane, BLR Partners LP, BLRPart, LP, BLRGP Inc., Fondren Management, LP, FMLP Inc., The Radoff Family Foundation and Bradley L. Radoff Stockholder Agreement, dated as of December 22, 2015, by and among VAALCO Energy, Inc., Kornitzer Capital Management, Inc. and John C. Kornitzer (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on December 23, 2015, and incorporated herein by reference).
10.20	Stockholder Agreement, dated as of December 22, 2015, by and among VAALCO Energy, Inc., Kornitzer Capital Management, Inc. and John C. Kornitzer (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on December 23, 2015, and incorporated herein by reference).
10.21*	VAALCO Energy, Inc. 2016 Stock Appreciation Rights Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on March 15, 2016, and incorporated herein by reference).
10.22*	Form of Stock Appreciation Rights Agreement under the VAALCO Energy, Inc. 2016 Stock Appreciate Rights Plan (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on March 15, 2016, and incorporated herein by reference).
21.1(a)	List of subsidiaries of the Company
23.1(a)	Consent of BDO USA, LLP
23.2(a)	Consent of Deloitte & Touche LLP
23.3(a)	Consent of Netherland, Sewell & Associates, Inc. —Independent Petroleum Engineers
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
99.1(a)	Report of Netherland, Sewell & Associates, Inc. (International Properties)
101.INS(a)	XBRL Instance Document.
101.SCH(a)	XBRL Taxonomy Schema Document.
101.CAL(a)	XBRL Calculation Linkbase Document.
101.DEF(a)	XBRL Definition Linkbase Document.
101.LAB(a)	XBRL Label Linkbase Document.
101.PRE(a)	XBRL Presentation Linkbase Document.

(a) Filed herewith

(b) Furnished herewith

* Management contract or compensatory plan or arrangement

Item 16. Form 10-K Summary

None.

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VAALCO ENERGY, INC.
(Registrant)

By /s/ CARY BOUNDS
Cary Bounds
Chief Executive Officer

Dated March 7, 2018

In accordance with the Exchange Act, this report has been signed below on the 7th day of March, 2018, by the following persons on behalf of the registrant and in the capacities indicated.

Signature	Title
By: /s/ CARY BOUNDS Cary Bounds	Chief Executive Officer (Principal Executive Officer) and Director
By: /s/ PHILIP F. PATMAN, JR. Philip F. Patman, Jr.	Chief Financial Officer (Principal Financial Officer)
By: /s/ ELIZABETH D. PROCHNOW Elizabeth D. Prochnow	Chief Accounting Officer (Principal Accounting Officer)
By: /s/ ANDREW L. FAWTHROP Andrew L. Fawthrop	Chairman of the Board and Director
By: /s/ MICHAEL KEANE Michael Keane	Vice Chairman and Director
By: /s/ A. JOHN KNAPP, JR. A. John Knapp, Jr.	Director

By:	/s/ JOHN J. MYERS, JR. John J. Myers, Jr.	Director
By:	/s/ STEVEN J. PULLY Steven J. Pully	Director

Report of Independent Registered Public Accounting Firm

Shareholders and Board of Directors

VAALCO Energy, Inc.

Houston, Texas

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of VAALCO Energy, Inc. (the “Company”) and subsidiaries as of December 31, 2017 and 2016, the related consolidated statements of operations, shareholders’ equity (deficit), and cash flows for the years then ended, and the related notes and financial statement schedule listed in the accompanying index as of and for the years ended December 31, 2017 and 2016 (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of VAALCO Energy, Inc. and subsidiaries as of December 31, 2017 and 2016, and the results of their operations and their cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

We also have audited the adjustments to the 2015 consolidated financial statements to retrospectively reflect the operations attributable to the Company’s activities in Angola as discontinued operations as described in Note 5. In our opinion, such adjustments are appropriate and have been properly applied. We were not engaged to audit, review, or apply any procedures to the 2015 consolidated financial statements of VAALCO Energy, Inc. and subsidiaries other than with respect to the adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 2015 consolidated financial statements taken as a whole.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”) and our report dated March 7, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

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

/s/ BDO USA, LLP

We have served as the Company's auditor since 2016.

Houston, Texas

March 7, 2018

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of VAALCO Energy, Inc. and subsidiaries:

We have audited, before the effects of the retrospective adjustments for the discontinued operations as discussed in Note 5 to the consolidated financial statements, the consolidated statements of operations, shareholders’ equity (deficit), and cash flows of VAALCO Energy, Inc. and subsidiaries (the "Company") for the year ended December 31, 2015 (the 2015 consolidated financial statements before the effects of the retrospective adjustments discussed in Note 5 to the consolidated financial statements are not presented herein). Our audit also includes the financial statement schedule listed in the index at item 15. These financial statements and financial statement schedule are the responsibility of the Company’s management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such 2015 consolidated financial statements, before the effects of the retrospective adjustments for the discontinued operations discussed in Note 5 to the consolidated financial statements, present fairly, in all material respects, the results of operations and cash flows of VAALCO Energy, Inc. and subsidiaries for the year ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic 2015 consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

The 2015 consolidated financial statements were prepared assuming that the Company would continue as a going concern. The Company's 2015 recurring losses from operations and insufficient liquidity due to depressed oil and gas prices, raised substantial doubt about its ability to continue as a going concern. The 2015 consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

We were not engaged to audit, review, or apply any procedures to the retrospective adjustments for the discontinued operations discussed in Note 5 to the consolidated financial statements and, accordingly, we do not express an opinion or any other form of assurance about whether such retrospective adjustments are appropriate and have been properly applied. Those retrospective adjustments were audited by other auditors.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas

March 16, 2016

VAALCO ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2017	December 31, 2016
ASSETS	(in thousands)	
Current assets:		
Cash and cash equivalents	$ 19,669	$ 20,474
Restricted cash	842	741
Receivables:		
Trade	3,556	6,751
Accounts with partners, net of allowance of $0.5 million at December 31, 2017 and December 31, 2016	3,395	3,297
Other	100	120
Crude oil inventory	3,263	913
Prepayments and other	2,791	4,040
Current assets - discontinued operations	2,836	2,139
Total current assets	36,452	38,475
Property and equipment - successful efforts method:		
Wells, platforms and other production facilities	389,935	389,231
Undeveloped acreage	10,000	10,000
Equipment and other	9,432	9,779
	409,367	409,010
Accumulated depreciation, depletion, amortization and impairment	(386,146)	(380,991)
Net property and equipment	23,221	28,019
Other noncurrent assets:		
Restricted cash	967	918
Value added tax and other receivables, net of allowance of $6.5 million and $4.7 million at December 31, 2017 and December 31, 2016, respectively	6,925	5,110
Deferred tax asset	1,260	—
Abandonment funding	10,808	8,510
Total assets	$ 79,633	$ 81,032
LIABILITIES AND SHAREHOLDERS' EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	$ 11,584	$ 19,096
Accrued liabilities and other	12,991	10,506
Current portion of long term debt	6,666	7,500
Current liabilities - discontinued operations	15,347	18,452
Total current liabilities	46,588	55,554
Asset retirement obligations	20,163	18,612
Other long term liabilities	284	284

Long term debt, excluding current portion, net	2,309	6,940
Total liabilities	69,344	81,390
Commitments and contingencies (Note 9)		
Shareholders’ equity (deficit):		
Preferred stock, none issued, 500,000 shares authorized, $25 par value	—	—
Common stock, $0.10 par value; 100,000,000 shares authorized, 66,443,971 and 66,109,565 shares issued, 58,862,876 and 58,554,470 shares outstanding	6,644	6,611
Additional paid-in capital	71,251	70,268
Less treasury stock, 7,581,095 and 7,555,095 shares at cost	(37,953)	(37,933)
Accumulated deficit	(29,653)	(39,304)
Total shareholders' equity (deficit)	10,289	(358)
Total liabilities and shareholders' equity (deficit)	$ 79,633	$ 81,032

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share amounts)

	Year Ended December 31,		
	2017	2016	2015
Revenues:			
Oil and natural gas sales	$ 77,025	$ 59,784	$ 80,445
Operating costs and expenses:			
Production expense	39,697	37,586	40,096
Exploration expense	7	5	10,409
Depreciation, depletion and amortization	6,457	6,926	32,998
General and administrative expense	10,377	9,561	12,294
Impairment of proved properties	—	88	81,322
Other operating expense	—	8,853	—
General and administrative related to shareholder matters	—	(332)	2,372
Bad debt expense and other	452	1,222	2,968
Total operating costs and expenses	56,990	63,909	182,459
Other operating income (expense), net	(84)	(266)	(1,092)
Operating income (loss)	19,951	(4,391)	(103,106)
Other income (expense):			
Interest expense, net	(1,414)	(2,613)	(1,325)
Other, net	2,113	(2,015)	(1,536)
Total other income (expense)	699	(4,628)	(2,861)
Income (loss) from continuing operations before income taxes	20,650	(9,019)	(105,967)
Income tax expense	10,378	9,248	14,587
Income (loss) from continuing operations	10,272	(18,267)	(120,554)
Loss from discontinued operations	(621)	(8,283)	(38,102)
Net income (loss)	$ 9,651	$ (26,550)	$ (158,656)
Basic net income (loss) per share:			
Income (loss) from continuing operations	$ 0.17	$ (0.31)	$ (2.07)
Loss from discontinued operations	(0.01)	(0.14)	(0.65)
Net income (loss) per share	$ 0.16	$ (0.45)	$ (2.72)
Basic weighted average shares outstanding	58,717	58,384	58,289
Diluted net income (loss) per share:			
Income (loss) from continuing operations	$ 0.17	$ (0.31)	$ (2.07)
Loss from discontinued operations	(0.01)	(0.14)	(0.65)
Net income (loss) per share	$ 0.16	$ (0.45)	$ (2.72)
Diluted weighted average shares outstanding	58,720	58,384	58,289

See notes to consolidated financial statements

VAALCO ENERGY, INC AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (DEFICIT)

(in thousands)

	Common Shares Issued	Treasury Shares	Common Stock	Additional Paid-In Capital	Treasury Stock	Retained Earnings (Deficit)	Total
Balance at January 1, 2015	65,195	(7,394)	$ 6,519	$ 64,351	$ (37,299)	$ 146,892	$ 180,463
Shares issued - stock-based compensation	846	—	85	957	—	—	1,042
Stock-based compensation expense	—	—	—	3,810	—	—	3,810
Treasury stock acquired	—	(120)	—	—	(583)	—	(583)
Net loss	—	—	—	—	—	(158,656)	(158,656)
Balance at December 31, 2015	66,041	(7,514)	6,604	69,118	(37,882)	(11,764)	26,076
Cumulative effect adjustment for adoption of ASU 2016-09	(420)	—	(42)	1,032	—	(990)	—
Balance at January 1, 2016 after cumulative effect adjustments	65,621	(7,514)	6,562	70,150	(37,882)	(12,754)	26,076
Shares issued - stock-based compensation	489	—	49	(49)	—	—	—
Stock-based compensation expense	—	—	—	167	—	—	167
Treasury stock acquired	—	(41)	—	—	(51)	—	(51)
Net loss	—	—	—	—	—	(26,550)	(26,550)
Balance at December 31, 2016	66,110	(7,555)	6,611	70,268	(37,933)	(39,304)	(358)
Shares issued - stock-based compensation	334	—	33	6	—	—	39
Stock-based compensation expense	—	—	—	977	—	—	977
Treasury stock acquired	—	(26)	—	—	(20)	—	(20)

Net income	—	—	—	—	—	9,651	9,651
Balance at December 31, 2017	66,444	(7,581)	$ 6,644	$ 71,251	$ (37,953)	$ (29,653)	$ 10,289

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 9,651	$ (26,550)	$ (158,656)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Loss from discontinued operations	621	8,283	38,102
Depreciation, depletion and amortization	6,457	6,926	32,998
Other amortization	369	1,424	304
Deferred taxes	(1,260)	—	1,349
Unrealized foreign exchange gain	(576)	(32)	(5,243)
Dry hole costs and impairment of unproved leasehold	—	—	10,244
Stock-based compensation	1,098	192	3,810
Commodity derivatives loss	1,032	1,711	—
Cash settlements received on matured derivative contracts	195	—	—
Bad debt provision	452	1,222	2,699
Other operating (income) loss, net	84	266	1,092
Operational expenses associated with equipment and other	1,189	—	—
Impairment of proved properties	—	88	81,322
Change in operating assets and liabilities:			
Trade receivables	3,195	(1,050)	14,174
Accounts with partners	(108)	16,284	(13,816)
Other receivables	(43)	(18)	(609)
Crude oil inventory	(2,350)	(192)	1,266
Value added tax and other receivables	(3,025)	(1,937)	(2,286)
Other long-term assets	(2,298)	(2,827)	(1,566)
Prepayments and other	1,646	517	3,129
Accounts payable	(7,297)	(15,459)	30,187
Accrued liabilities and other	2,050	(4,586)	3,034
Net cash provided by (used in) continuing operating activities	11,082	(15,738)	41,534
Net cash provided by (used in) discontinued operating activities	(4,423)	12,286	(2,659)
Net cash provided by (used in) operating activities	6,659	(3,452)	38,875
CASH FLOWS FROM INVESTING ACTIVITIES:			
(Increase) decrease in restricted cash	(150)	15,219	5,536
Acquisitions	64	(5,692)	—
Property and equipment expenditures	(1,813)	(8,705)	(68,067)
Proceeds from the sale of oil and gas properties	250	830	398
Premiums paid for put options	—	(2,939)	—
Net cash used in continuing investing activities	(1,649)	(1,287)	(62,133)
Net cash used in discontinued investing activities	—	—	(20,877)

Net cash used in investing activities	(1,649)	(1,287)	(83,010)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from the issuances of common stock	39	—	441
Treasury shares	(20)	(51)	—
Debt issuance costs	—	(93)	—
Debt repayment	(10,001)	—	—
Borrowings	4,167	—	—
Net cash provided by (used in) continuing financing activities	(5,815)	(144)	441
Net cash provided by discontinued financing activities	—	—	—
Net cash provided by (used in) financing activities	(5,815)	(144)	441
NET CHANGE IN CASH AND CASH EQUIVALENTS	(805)	(4,883)	(43,694)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	20,474	25,357	69,051
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 19,669	$ 20,474	$ 25,357

See notes to consolidated financial statements.

	Year Ended December 31,		
	2017	2016	2015
	(in thousands)		
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalized interest	$ 997	$ 1,326	$ 1,337
Income taxes paid	$ 15,153	$ 9,210	$ 15,163
Supplemental disclosure of non-cash investing and financing activities:			
Property and equipment additions incurred but not paid at period end	$ 455	$ 2,282	$ 15,132
Asset retirement obligations	$ 600	$ 1,543	$ 542

See notes to consolidated financial statements.

VAALCO ENERGY, INC AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION

VAALCO Energy, Inc. and its consolidated subsidiaries (“VAALCO” or the “Company”) is a Houston, Texas based independent energy company engaged in the acquisition, exploration, development and production of crude oil. As operator, we have production operations and conduct exploration activities in Gabon, West Africa. As non-operator, we have opportunities to participate in development and exploration activities in Equatorial Guinea, West Africa. As discussed further in Note 5 below, we have discontinued operations associated with our activities in Angola, West Africa.

Our consolidated subsidiaries are VAALCO Gabon (Etame), Inc., VAALCO Production (Gabon), Inc., VAALCO Gabon S.A., VAALCO Angola (Kwanza), Inc., VAALCO UK (North Sea), Ltd., VAALCO International, Inc., VAALCO Energy (EG), Inc., VAALCO Energy Mauritius (EG) Limited and VAALCO Energy (USA), Inc.

2. LIQUIDITY

Our revenues, cash flow, profitability, oil and natural gas reserve values and future rates of growth are substantially dependent upon prevailing prices for oil and natural gas. Our ability to borrow funds and to obtain additional capital on attractive terms is also substantially dependent on oil and natural gas prices. After a period of low commodity prices, oil and gas prices have stabilized at levels which are currently adequate to generate cash from operating activities for our continuing operations. In addition to the impact of oil and gas prices on our access to capital markets, the availability of capital resources on attractive terms may be limited due to the geographic location of our primary producing assets. We may drill two or three development wells in 2018. Any drilling program we enter into would require approval of our partners and the government of Gabon. We expect any capital expenditures made during 2018 will be funded by cash on hand, cash flow from operations and cash raised from debt and/or equity issuances. We believe that at current prices, cash generated from continuing operations together with cash on hand at December 31, 2017 are adequate to support our operations and cash requirements during 2018 and through March 31, 2019.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of consolidation – The accompanying consolidated financial statements (“Financial Statements”) include the accounts of VAALCO and its wholly owned subsidiaries. Investments in unincorporated joint ventures and undivided interests in certain operating assets are consolidated on a pro rata basis. All intercompany transactions within the consolidated group have been eliminated in consolidation.

Reclassifications – Certain reclassifications have been made to prior period amounts to conform to the current period presentation related to reclassifying material and supplies to prepayments and other. These reclassifications did not affect our consolidated financial results.

Use of estimates – The preparation of the Financial Statements in conformity with generally accepted accounting principles in the United States (“GAAP”) requires estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the Financial Statements and the reported amounts of revenues and expenses during the respective reporting periods. Our Financial Statements include amounts that are based on management’s best estimates and judgments. Actual results could differ from those estimates.

Estimates of oil and natural gas reserves used to estimate depletion expense and impairment charges require extensive judgments and are generally less precise than other estimates made in connection with financial disclosures. Due to inherent uncertainties and the limited nature of data, estimates are imprecise and subject to change over time as additional information become available.

Cash and cash equivalents – Cash and cash equivalents includes deposits and funds invested in highly liquid instruments with original maturities of three months or less at the date of purchase.

Restricted cash and abandonment funding – Restricted cash includes cash that is contractually restricted. Restricted cash is classified as a current or non-current asset based on its designated purpose and time duration. Current amounts in restricted cash at December 31, 2017 and 2016 each include an escrow amount representing bank guarantees for customs clearance in Gabon. Long term amounts at December 31, 2017 and 2016 include a charter payment escrow for the floating, production, storage and offloading vessel ("FPSO") offshore Gabon as discussed in Note 9.

We invest restricted and excess cash in certificates of deposit and commercial paper issued by banks with maturities typically not exceeding 90 days.

Accounts with partners – Accounts with partners represent the excess of charges billed over cash calls paid by the partners for exploration, development and production expenditures made by us as an operator.

Bad debts – Quarterly, we evaluate our accounts receivable balances to confirm collectability. When collectability is in doubt, we record an allowance against the accounts receivable and a corresponding income charge for bad debts which appears in the “Bad debt expense and other” line item of the consolidated statements of operations. The majority of our accounts receivable balances are with our joint venture partners, purchasers of our production and the government of Gabon for reimbursable Value-Added Tax (“VAT”). Collection efforts, including remedies provided for in the contracts, are pursued to collect overdue amounts owed us. Portions of our costs in Gabon (including our VAT receivable) are denominated in the local currency of Gabon, the Central African CFA Franc (“XAF”). As of December 31, 2017, the outstanding VAT receivable balance, excluding the allowance for bad debt, was approximately XAF 21.2 billion (XAF 7.1 billion, net to VAALCO). As of December 31, 2017, the exchange rate was XAF 547.5 = $1.00.

In June 2016, we entered into an agreement with the government of Gabon to receive payments related to the outstanding VAT receivable balance of XAF 16.3 billion (XAF 4.9 billion, net to VAALCO), representing the outstanding balance as of December 31, 2015, in thirty-six monthly installments of $0.3 million net to VAALCO. We received one monthly installment payment in July 2016; however, no further payments have been received as of December 31, 2017. We are in discussions with the Gabonese government regarding the timing of the resumption of payments.

In 2017, 2016 and 2015, we recorded allowances of $0.4 million, $0.7 million and $2.7 million, respectively, related to VAT which the government of Gabon has not reimbursed. The receivable amount, net of allowances, is reported as a non-current asset in the “Value added tax and other receivables” line item in the consolidated balance sheets. Because both the VAT receivable and the related allowance are denominated in XAF, the exchange rate revaluation of these balances into U.S. dollars at the end of each reporting period also has an impact on profit/loss. Such foreign currency gains/(losses) are reported separately in the “Other, net” line item of the consolidated statements of operations.

The following table provides an analysis of the change in the allowance:

	Year Ended December 31,		
	2017	2016	2015
	(in thousands)		
Allowance for bad debt			
Balance at beginning of year	$ (5,211)	$ (4,221)	$ (2,400)
Charge to cost and expenses	(452)	(1,222)	(2,699)
Reclassification related to Sojitz acquisition	(694)	—	—
Foreign currency gain (loss)	(676)	232	878
Balance at end of period	$ (7,033)	$ (5,211)	$ (4,221)

Crude oil inventory – Crude oil inventories are carried at the lower of cost or market and represent our share of crude oil produced and stored on the FPSO, but unsold at the end of the period.

Materials and supplies – Materials and supplies, which are included in the “Prepayments and other” line item of the consolidated balance sheet, are primarily used for production related activities. These assets are valued at the lower of cost, determined by the weighted-average method, or market.

Property and equipment – We use the successful efforts method of accounting for oil and natural gas producing activities.

Capitalization – Leasehold acquisition costs are initially capitalized. Costs to drill exploratory wells are initially capitalized until a determination as to whether proved reserves have been discovered. If an exploratory well is deemed to not have found proved reserves, the associated costs are charged to exploration expense at that time. Exploration costs, other than the cost of drilling exploratory wells, which can include geological and geophysical expenses applicable to undeveloped leasehold, leasehold expiration costs and delay rentals are charged to exploration expense as incurred. All development costs, including developmental dry hole costs, are capitalized.

Impairment – We review our oil and natural gas producing properties for impairment on a field-by-field basis quarterly or whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment charge is recorded based on the fair value of the asset. We evaluate our undeveloped oil and natural gas leases for impairment periodically by considering numerous factors that could include nearby drilling results, seismic interpretations, market values of similar assets, existing contracts, lease expiration terms and future plans for exploration or development. When undeveloped oil and natural gas leases are deemed to be impaired, exploration expense is charged. Capitalized equipment inventory is reviewed regularly for obsolescence. We identified equipment inventory in Gabon that we do not expect to use and charged \$0.3 million, \$0.3 million and \$1.5 million to the “Other operating loss, net” line item of the consolidated statement of operations in the years ended December 31, 2017, 2016 and 2015, respectively.

Depreciation, depletion and amortization – Depletion of wells, platforms, and other production facilities are calculated on a field basis under the unit-of-production method based upon estimates of proved developed reserves. Depletion of developed leasehold acquisition costs are provided on a field basis under the unit-of-production method based upon estimates of proved reserves. Support equipment and leasehold improvements related to oil and natural gas producing activities, as well as property, plant and equipment unrelated to oil and natural gas producing activities, are recorded at cost and depreciated on a straight-line basis over the estimated useful lives of the assets, which are typically five years for office and miscellaneous equipment and five to seven years for leasehold improvements.

Capitalized interest – Interest costs and commitment fees from external borrowings are capitalized on exploration and development projects that are not subject to current depletion. Interest and commitment fees are capitalized only for the period that activities are in progress to bring these projects to their intended use. Capitalized interest is added to the cost of the underlying asset and is depleted on the unit-of-production method in the same manner as the underlying assets.

We capitalized no interest costs for the years ended December 31, 2017 or 2016. We capitalized $0.8 million in interest costs during the year ended December 31, 2015.

Asset retirement obligations ("ARO") – We have significant obligations to remove tangible equipment and restore land or seabed at the end of oil and natural gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells, removing and disposing of all or a portion of offshore oil and natural gas platforms, and capping pipelines. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations.

A liability for ARO is recognized in the period in which the legal obligations are incurred if a reasonable estimate of fair value can be made. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with our oil and natural gas properties. We use current retirement costs to estimate the expected cash outflows for retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. Initial recording of the ARO liability is offset by the corresponding capitalization of asset retirement cost recorded to oil and natural gas properties. To the extent these or other assumptions change after initial recognition of the liability, the fair value estimate is revised and the recognized liability adjusted, with a corresponding adjustment made to the related asset balance or income statement, as appropriate. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is generally determined on a units-of-production basis for oil and natural gas production facilities, while accretion escalates over the lives of the assets to reach the expected settlement value. See Note 7 for disclosures regarding our asset retirement obligations.

Revenue recognition – We recognize oil and natural gas revenues when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred and collectability of the revenue is reasonably assured. We follow the sales method of accounting for crude oil and natural gas production imbalances. We recognize revenues on the volumes sold based on the provisional sales prices. The volumes sold may be more or less than the volumes to which we are entitled based on our ownership interest in the property, and we would recognize a liability if our existing proved reserves were not adequate to cover an imbalance. As of December 31, 2017 and 2016, we had no recorded oil and natural gas imbalances.

Major maintenance activities – Costs for major maintenance are expensed in the period incurred and can include the costs of workovers of existing wells, contractor repair services, materials and supplies, equipment rentals and our labor costs.

Stock based compensation - We measure the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant. Grant date fair value for options is estimated using the Black-Scholes option pricing model. The model employs various assumptions, based on management's best estimates at the time of grant, which impact the calculation of fair value and ultimately, the amount of expense that is recognized over the life of the stock option award. For restricted stock, grant date fair value is determined using the market value of our common stock on the date of grant. The fair value of stock appreciation rights (“SARs”) is based on a Monte Carlo simulation at grant date and at each subsequent reporting date. The Monte Carlo simulation to value our SARs uses the following inputs: (i) the quoted market price of our common stock on the valuation date, (ii) the maximum stock price appreciation that an employee may receive, (iii) the expected term which is based on the contractual term, (iv) the expected volatility which is based on the historical volatility of the our stock for the length of time corresponding to the expected term of the SARs, (v) the expected dividend yield is based on our anticipated dividend payments, (vi) the risk-free interest rate which is based on the U.S. treasury yield curve in effect as of the reporting date for the length of time corresponding to the expected term of the SARs.

Our stock-based compensation expense is recognized based on the awards as they vest, using the straight-line attribution method over the requisite service period for each separately vesting portion of the award as if the award was, in-substance, multiple awards.

When awards are forfeited before they vest, previously recognized expense related to such forfeitures is reversed in the period in which the forfeiture occurs.

Foreign currency transactions – The U.S. dollar is the functional currency of our foreign operating subsidiaries. Gains and losses on foreign currency transactions are included in income. Within the consolidated statements of operations line item “Other income (expense)—Other, net,” we recognized gains on foreign currency transactions of $0.5 million in 2017, while we recognized losses on foreign currency transactions of $30 thousand and $0.8 million in 2016 and 2015, respectively.

Income taxes – We account for income taxes under an asset and liability approach that recognizes deferred income tax assets and liabilities for the estimated future tax consequences of differences between the Financial Statements and tax bases of assets and liabilities. Valuation allowances are provided against deferred tax assets that are not likely to be realized. We report interest related to income tax liabilities in the "Interest expense" line item on the consolidated statements of operations, and we report penalties in the "Other, net" line item on the consolidated statements of operations.

Derivative Instruments and Hedging Activities – We use derivative financial instruments to achieve a more predictable cash flow from oil production by reducing our exposure to price fluctuations. Our derivative instruments at December 31, 2016 consisted of fixed price oil puts, which give us the option to sell a contracted volume of oil at a contracted price on a contracted date in the future.
All of our oil put contracts, which provided for settlement based upon reported the Brent price, had expired as of December 31, 2017.

We record balances resulting from commodity risk management activities in the consolidated balance sheets as either assets or liabilities measured at fair value. Gains and losses from the change in fair value of derivative instruments and cash settlements on commodity derivatives are presented in the "Other, net" line item located within the "Other income (expense)" section of the consolidated statements of operations. We received cash settlements of $0.2 million during the year ended December 31, 2017 related to matured derivative contracts.

Fair Value – Fair value is defined as the price that would be received to sell an asset or the price paid to transfer a liability in an orderly transaction between market participants at the measurement date. Inputs used in determining fair value are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. The three input levels of the fair-value hierarchy are as follows:

Level 1 – Inputs represent quoted prices in active markets for identical assets or liabilities (for example, exchange-traded commodity derivatives).

Level 2 – Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).

Level 3 – Inputs that are not observable from objective sources, such as internally developed assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in our internally developed present value of future cash flows model that underlies the fair-value measurement).

Fair value of financial instruments – Our current assets and liabilities include financial instruments such as cash and cash equivalents, restricted cash, accounts receivable, derivative assets, accounts payable and guarantee. As discussed further in Note 10, derivative assets and liabilities are measured and reported at fair value each period with changes in fair value recognized in net income. With respect to our other financial instruments included in current assets and liabilities, the carrying value of each financial instrument approximates fair value primarily due to the short-term maturity of these instruments. The carrying value of our long-term debt approximates fair value, as the interest rates are adjusted based on market rates currently in effect.

General and administrative related to shareholder matters – Amounts related to shareholder matters for the years ended December 31, 2016 and 2015 relate to costs incurred related to shareholder litigation that was settled in 2016. For 2016, the amounts also include the offsetting insurance proceeds related to these matters.

Other, net – “Other, net” in non-operating income and expenses includes gains and losses from derivatives and foreign currency transactions as discussed above. In addition, “Other, net” for the year ended December 31, 2017 includes $2.6 million related to the reversal of accruals for liabilities we are no longer obligated to pay.

4. NEW ACCOUNTING STANDARDS

Not Yet Adopted

In May 2017, the Financial Accounting Standards Board (“FASB”) issued ASU No. 2017-09, Compensation – Stock Compensation (Topic 718): Scope of Modification Accounting (ASU 2017-09) to clarify when to account for a change to the terms or conditions of a share-based payment award as a modification. Under ASU 2017-09, modification accounting is required only if the fair value, the vesting conditions, or the classification of the award (as equity or liability) changes as a result of the change in terms or conditions. The amendments in ASU 2017-09 are effective for all entities for interim and annual reporting periods beginning after December 15, 2017. The amendments in this update are to be applied prospectively to an award modified on or after the adoption date. It has not been the Company’s practice to make modifications to share-based payment awards which would have been impacted by this standard, and while there can be no assurance that this will not occur in future periods, we do not expect adoption of this standard to have a material impact on our financial position, results of operations, cash flows and related disclosures.

In January 2017, the FASB issued ASU No. 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business (ASU 2017-01”). The purpose of the amendment is to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. For public entities, the amendments in ASU 2017-01 are effective for interim and annual reporting periods beginning after December 15, 2017. The amendments in this update are to be applied prospectively to acquisitions and disposals completed on or after the effective date, with no disclosures required at transition. The adoption of ASU 2017-01 is not expected to have a material impact on our financial position, results of operations, cash flows and related disclosures.

In November 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash ("ASU 2016-18"), which requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. ASU 2016-18 is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted. We do not plan to early adopt this standard. Restricted cash will be included as a component of Cash, cash equivalents and restricted cash on our Consolidated Statement of Cash Flows for all periods presented. Due to the nature of this accounting standards update, this will have an impact on items reported in our statements of cash flows, but no impact is expected on our financial position, results of operations or related disclosures as a result of implementation.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments ("ASU 2016-15") related to how certain cash receipts and payments are presented and classified in the statement of cash flows. These cash flow issues include debt prepayment or extinguishment costs, settlement of zero-coupon debt, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, distributions received from equity method investees, beneficial interests in securitization transactions, and separately identifiable cash flows. ASU 2016-15 is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Due to the nature of this accounting standards update, this may have an impact on items reported in our statements of cash flows, but no impact is expected on our financial position, results of operations or related disclosures as a result of implementation.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments ("ASU 2016-13") related to the calculation of credit losses on financial instruments. All financial instruments not accounted for at fair value will be impacted, including our trade and partner receivables. Allowances are to be measured using a current expected credit loss model as of the reporting date which is based on historical experience, current conditions and reasonable and supportable forecasts. This is significantly different from the current model which increases the allowance when losses are probable. This change is effective for all public companies for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years and will be applied with a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. We are currently evaluating the provisions of ASU 2016-13 and are assessing its potential impact on our financial position, results of operations, cash flows and related disclosures.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) ("ASU 2016-02"), which amends the accounting standards for leases. ASU 2016-02 retains a distinction between finance leases and operating leases. The primary change is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases on the balance sheet. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous guidance. Certain aspects of lease accounting have been simplified and additional qualitative and quantitative disclosures are required along with specific quantitative disclosures required by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The amendments are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early application permitted. We are required to use a modified retrospective approach for leases that exist or are entered into after the beginning of the earliest comparative period presented in the financial statements. Assuming adoption

January 1, 2019, we expect that leases in effect on January 1, 2017 and leases entered into after such date will be reflected in accordance with the new standard in the audited consolidated financial statements included in our Annual Report on Form 10-K for 2019, including comparative financial statements presented in such report. We are in the early stages of our gap assessment, but we expect that leases with terms greater than 12 months which are currently treated as operating leases will be capitalized. We expect adoption of this standard to result in the recording of a right of use asset related to certain of our operating leases with a corresponding lease liability. This is expected to result in a material increase in total assets and liabilities as certain of our operating leases are significant as disclosed in Note 9. We do not expect there will be a material overall impact on results of operations or cash flows. We have developed an implementation plan related to this new standard. In connection with our implementation plan, we will be reviewing our lease contracts and evaluating other contracts to identify embedded leases and determining the appropriate accounting treatment, and we will be evaluating the impact on processes and procedures as well as the internal controls related to the proper accounting for leases under the new standard.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) (“ASU 2014-09”). The new standard will replace most existing revenue recognition guidance in U.S. GAAP. The core principle of ASU 2014-09 requires companies to reevaluate when revenue is recorded on a transaction based upon newly defined criteria, either at a point in time or over time as goods or services are delivered. The ASU requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts, including significant judgments and estimates, and changes in those estimates. In early 2016, the FASB issued additional guidance: ASU No. 2016-10, 2016-11 and 2016-12 (and together with ASU 2014-09, “Revenue Recognition ASU”). These updates provide further guidance and clarification on specific items within the previously issued ASU 2014-09. The Revenue Recognition ASU becomes effective for the Company as of January 1, 2018, with the option to early adopt the standard for annual periods beginning on or after December 15, 2016, and allows for both retrospective and modified-retrospective methods of adoption. The Company did not early adopt the standard. We adopted the Revenue Recognition ASU via the modified retrospective transition method. We have completed our gap assessment and have determined that we qualify for point in time recognition for essentially all of our sales. As such, the Company's adoption of this standard did not result in a change in the timing of revenue recognition compared to current practices, and therefore we do not expect adoption of this standard to have a material impact on our financial position, results of operations, debt covenants or business practices. As required by the new standard, we will have expanded disclosures related to the nature of our sales contracts and other matters related to revenues and the accounting for revenues. In addition, for the periods beginning January 1, 2018, we have implemented new internal controls and procedures associated with revenue recognition.

Adopted

In July 2015, the FASB issued ASU No. 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory (ASU 2015-11) to simplify the measurement of inventory. This simplification applies to all inventory other than that measured using last-in, first out ("LIFO") or the retail inventory method and requires measurement of inventory at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable cost of completion, disposal and transportation. This guidance is to be applied prospectively effective for annual periods beginning after December 15, 2016, and interim periods within annual periods beginning after December 15, 2016. We adopted ASU 2015-11 in the first quarter of 2017, and the application of this guidance did not have a significant impact on our financial position, results of operations or cash flows.

5. ACQUISITIONS AND DISPOSITIONS

Sojitz Acquisition

On November 22, 2016, we closed on the purchase of an additional 2.98% working interest (3.23% participating interest) in the Etame Marin block located offshore the Republic of Gabon from Sojitz Etame Limited ("Sojitz"), which represents all interest owned by Sojitz in the concession. The acquisition had an effective date of August 1, 2016 and was funded with cash on hand.

The following amounts represent the fair value of identifiable assets acquired and liabilities assumed in the Sojitz acquisition.

	November 22, 2016 (in thousands)
Assets acquired:	
Wells, platforms and other production facilities	$ 5,754
Equipment and other	684
Value added tax and other receivables	297
Abandonment funding	546

Accounts receivable - trade		888
Prepayments and other		220
Liabilities assumed:		
Asset retirement obligations		(1,731)
Accrued liabilities and other		(747)
Total identifiable net assets and consideration transferred	$	5,911

All assets and liabilities associated with Sojitz's interest in Etame Marin block, including oil and gas properties, asset retirement obligations and working capital items were recorded at their fair value. In determining the fair value of the oil and gas properties, we prepared estimates of oil and natural gas reserves. We used estimated future prices to apply to the estimated reserve quantities acquired and the estimated future operating and development costs to arrive at the estimates of future net revenues. The valuations to derive the purchase price included the use of both proved and unproved categories of reserves, expectation for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates, and risk adjusted discount rates. Other significant estimates were used by management to calculate fair value of assets acquired and liabilities assumed. These assumptions represent Level 3 inputs, as further discussed in Note 3.

The actual impact of the Sojitz Acquisition was an increase to "Total revenues" in the consolidated statement of operations of $0.2 million for the year ended December 31, 2016 and a minimal decrease to "Net loss" in the consolidated statement of operations for the year ended December 31, 2016. The unaudited pro forma results presented below have been prepared to give the effect of the acquisition discussed above on our results of operations for the years ended December 31, 2016 and 2015 as if it had been consummated on January 1, 2015. The unaudited pro forma results do not purport to represent what our actual results of operations would have been if the acquisition had been completed on such date or to project our results of operations for any future date or period.

	Year Ended December 31,	
	2016	2015
	(in thousands)	
Pro forma (unaudited)		
Oil and natural gas sales	$ 65,427	$ 88,940
Operating loss	(4,295)	(101,494)
Loss from continuing operations	(19,232)	(120,546)
Basic and diluted net loss per share:		
Loss from continuing operations	$ (0.33)	$ (2.07)
Net loss	$ (0.47)	$ (2.72)

Sale of Certain U.S. Properties

During 2015, we completed the sale of our interests in various wells in Texas and Alabama for $0.4 million resulting in a minimal loss. In December 2016, we completed the sale of our interests in two wells in the Hefley field in North Texas for $0.8 million resulting in a minimal loss. In April 2017, we completed the sale of our interests in the East Poplar Dome field in Montana for $0.3 million, resulting in a gain of approximately $0.3 million reported on the line "Other operating income (expense), net" in our results of operations for the year ended December 31, 2017.

Discontinued Operations - Angola

In November 2006, we signed a production sharing contract for Block 5 offshore Angola ("PSA"). The four year primary term, referred to as the Initial Exploration Phase ("IEP"), with an optional three year extension, awarded us exploration rights to 1.4 million acres offshore central Angola, with a commitment to drill two exploratory wells. The IEP was extended on two occasions to run until December 1, 2014. In October 2014, we entered into the Subsequent Exploration Phase ("SEP") which extended the exploration period to November 30, 2017 and required us and the co-participating interest owner, the Angolan national oil company, Sonangol P&P, to drill two additional exploration wells. Our working interest is 40%, and it carries Sonangol P&P, for 10% of the work program. On September 30, 2016, we notified Sonangol P&P that we were withdrawing from the joint operating agreement effective October 31, 2016. On November 30, 2016, we notified the national concessionaire, Sonangol E.P., that we were withdrawing from the PSA. Further to the decision to withdraw from Angola, we have taken actions to close our office in Angola and reduce future activities in Angola. As a result of this strategic shift, we classified all the related assets and liabilities as those of discontinued operations in the condensed consolidated balance sheets. The operating results of the Angola segment have been classified as discontinued operations for all periods presented in our condensed consolidated statements of operations. We segregated the cash flows attributable to the Angola segment from the cash flows from continuing operations for all periods presented in our condensed consolidated statements of cash flows. The following tables summarize selected financial information related to the Angola segment assets and liabilities as of December 31, 2017 and 2016 and its results of operations for the years ended December 31, 2017, 2016 and 2015.

Summarized Results of Discontinued Operations

	Year Ended December 31,		
	2017	2016	2015
	(in thousands)		
Operating costs and expenses:			

Exploration expense	$ —	$ 15,137	$ 36,044
Depreciation, depletion and amortization	—	9	12
General and administrative expense	615	1,269	2,535
Bad debt recovery and other	—	(7,629)	—
Total operating costs, expenses and (recovery)	615	8,786	38,591
Other operating loss, net	—	(172)	(1,856)
Operating loss	(615)	(8,958)	(40,447)
Other income (expense):			
Interest income	—	3,201	—
Other, net	(3)	552	2,345
Total other income (expense)	(3)	3,753	2,345
Loss from discontinued operations before income taxes	(618)	(5,205)	(38,102)
Income tax expense	3	3,078	—
Loss from discontinued operations	$ (621)	$ (8,283)	$ (38,102)

Assets and Liabilities Attributable to Discontinued Operations

	December 31,	
	2017	2016
	(in thousands)	
ASSETS		
Accounts with partners	$ 2,836	$ 2,139
Total current assets	2,836	2,139
Total assets	$ 2,836	$ 2,139
LIABILITIES		
Current liabilities:		
Accounts payable	$ 158	$ 77
Foreign taxes payable	—	3,078
Accrued liabilities and other	15,189	15,297
Total current liabilities	15,347	18,452
Total liabilities	$ 15,347	$ 18,452

Drilling Obligation

Under the PSA, we and the other participating interest owner, Sonangol P&P, were obligated to perform exploration activities that included specified seismic activities and drilling a specified number of wells during each of the exploration phases identified in the PSA. The specified seismic activities were completed, and one well, the Kindele #1 well, was drilled in 2015. The PSA provides a stipulated payment of $10.0 million for each exploration well for which a drilling obligation remains under the terms of the PSA, of which our participating interest share would be $5.0 million per well. We have reflected an accrual of $15.0 million for a potential payment as of December 31, 2017 and 2016, respectively, which represents what we believe to be the maximum potential amount attributable to VAALCO Angola's interest under the PSA.

Other Matters – Partner Receivable

The government-assigned working interest partner was delinquent in paying their share of the costs several times in 2009 and was removed from the production sharing contract in 2010 by a governmental decree. Efforts to collect from the defaulted partner were abandoned in 2012. The available 40% working interest in Block 5, offshore Angola was assigned to Sonangol P&P effective on January 1, 2014. We invoiced Sonangol P&P for the unpaid delinquent amounts from the defaulted partner plus the amounts incurred during the period prior to assignment of the working interest totaling $7.6 million plus interest in April 2014. Because this amount was not paid and Sonangol P&P was slow in paying monthly cash call invoices since their assignment, we placed Sonangol P&P in default in the first quarter of 2015.

On March 14, 2016, we received a $19.0 million payment from Sonangol P&P for the full amount owed us as of December 31, 2015, including the $7.6 million of pre-assignment costs and default interest of $3.2 million. The $7.6 million recovery is reflected in the "Bad debt expense and other" line item in our summarized results of discontinued operations. Default interest of $3.2 million is shown in the "Interest income" line item in our summarized results of discontinued operations.

6. OIL AND NATURAL GAS PROPERTIES AND EQUIPMENT

Proved Properties

We review our oil and natural gas producing properties for impairment quarterly or whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. When an oil and natural gas property's undiscounted estimated future net cash flows are not sufficient to recover its carrying amount, an impairment charge is recorded to reduce the carrying amount of the asset to its fair value. The fair value of the asset is measured using a discounted cash flow model relying primarily on Level 3 inputs into the undiscounted future net cash flows. The undiscounted estimated future net cash flows used in our impairment evaluations at each quarter end are based upon the most recently prepared independent reserve engineers' report adjusted to use forecasted prices from the forward strip price curves near each quarter end and adjusted as necessary for drilling and production results.

Declining forecasted oil prices in 2015 caused us to perform impairment reviews of our proved properties in each quarter of 2015 for all fields in the Etame Marin block offshore Gabon and the Hefley field in North Texas. For the Etame Marin fields, we recorded an aggregate impairment charge of $78.1 million for 2015, reducing the aggregate carrying value of these fields to an aggregate fair value of $12.7 million. For the U.S. fields, we recorded an impairment charge of $3.2 million for 2015 reducing the aggregate carrying value of the field to $1.2 million.

During 2016, our negative price differential to Brent narrowed and we incurred no significant capital spending. We considered these and other factors and determined that there were no events or circumstances triggering an impairment evaluation for most of our fields, with the exception of the Avouma field in the Etame Marine block offshore Gabon. At the Avouma field, the electrical submersible pumps ("ESPs") in the South Tchibala 2-H well and the Avouma 2-H well failed, and these wells were temporarily shut in. After utilizing a hydraulic workover unit to replace the failed ESP systems, the South Tchibala 2-H and the Avouma 2-H wells resumed production in December 2016 and January 2017, respectively. The reserves used in our impairment evaluation of the Avouma field prior to the fourth quarter of 2016 were revised to reflect the impact of this lost production for several months and the impact of the forward price curve. The undiscounted future net cash flows for the Avouma field were in excess of the field's carrying value at December 31, 2016. As a result, no impairment was required for the Avouma field, or any of our other fields in Gabon, for 2016.

There was no triggering event in the year ended December 31, 2017 that would cause us to believe the value of oil and natural gas producing properties should be impaired.

Undeveloped Leasehold Costs

We have a 31% working interest in an undeveloped portion of Block P offshore Equatorial Guinea that we acquired in 2012 for which we have $10.0 million capitalized in undeveloped acreage. It is currently unlikely that we will be making any near-term expenditures with respect to any development of this property. We and our partners will need to evaluate the timing and budgeting for exploration and development activities under a development and production area in the block, including the approval of a development and production plan to develop the Venus discovery on the block. Our production sharing contract covering this development and production area provides for a development and production period of 25 years from the date of approval of a development and production plan.

In September 2011, we acquired an interest in the Middle Bakken and deeper formations in the East Poplar unit and the Northwest Poplar field in Roosevelt County, Montana. Exploratory drilling required by terms of the acquisition was unsuccessful. Due to the sustained low oil prices and forward oil prices, we charged the full $1.2 million undeveloped leasehold to exploration expense in 2015.

Capitalized Exploratory Well Costs

At December 31, 2014, the drilling costs of the N'Gongui No. 2 discovery that was drilled in the third and fourth quarters of 2012 in the Mutamba Iroru block onshore Gabon were capitalized pending the determination of proved reserves.

Since this discovery, we have performed quarterly evaluations of the capitalized exploratory well costs for the N'Gongui No. 2 discovery to determine whether sufficient progress had been made towards development, as well as the economic and operational viability of the project. The evaluation of economic viability takes into account a number of factors, including alternative development scenarios, estimated reserves, projected drilling and development costs and projected oil price data. As a result of lower projected oil price data at September 30, 2015, the results from the economic modeling indicated that the costs for this well did not continue to meet the criteria for suspended well costs. Accordingly, all capitalized costs related to the project, including capitalized exploratory well costs were charged to exploration expense in the third quarter of 2015.

Capitalized Equipment Inventory

Capitalized equipment inventory in Gabon related to Mutamba was written off in 2015 because further drilling in the prospect is uneconomic, while equipment inventory related to the Etame Marin block was reduced in value due to obsolescence of some items.

7. ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in our asset retirement obligations:

(in thousands)	2017	2016	2015
Balance at January 1	$ 18,612	$ 16,166	$ 14,846
Accretion	951	903	778
Additions	—	—	1,085
Acquisitions and dispositions	(103)	1,544	—
Revisions	703	(1)	(543)
Balance at December 31	$ 20,163	$ 18,612	$ 16,166

Accretion is recorded in the line item “Depreciation, depletion and amortization” of our consolidated statements of operations.

We are required under the Etame PSC to conduct regular abandonment studies to update the estimated costs to abandon the offshore wells, platforms and facilities on the Etame Marin block. The most recently completed abandonment study was in January 2016. The final results of the abandonment study resulted in an increase in the costs necessary to fund future abandonment obligations.

8. DEBT

In January 2014, we executed a loan agreement with the International Finance Corporation (“IFC credit facility”) for a $65.0 million revolving credit facility, which was secured by the assets of our Gabon subsidiary. On June 29, 2016, we executed a supplemental agreement with the IFC which, among other things, amended and restated our existing loan agreement to convert the $20.0 million revolving portion of the credit facility, to a term loan with $15.0 million outstanding (“Amended Term Loan Agreement”). The

Amended Loan Agreement is secured by the assets of our Gabon subsidiary, VAALCO Gabon S.A., and is guaranteed by VAALCO as the parent company. The Amended Term Loan Agreement provides for quarterly principal and interest payments on the amounts currently outstanding through June 30, 2019, with interest accruing at a rate of LIBOR plus 5.75%.

The Amended Term Loan Agreement also provided for an additional $5.0 million, which could be requested in a single draw, subject to the IFC's approval, through March 15, 2017. On March 14, 2017, we borrowed $4.2 million under this provision of the Amended Term Loan Agreement. The additional borrowings will be repaid in five quarterly principal installments commencing June 30, 2017, together with interest which will accrue at LIBOR plus 5.75%.

The estimated fair value of the borrowings under the Amended Term Loan Agreement is $9.2 million when measured using a discounted cash flow model over the life of the current borrowings at forecasted interest rates. The inputs to this model are Level 3 in the fair value hierarchy.

Covenants

Under the Amended Term Loan Agreement, the ratio of quarter-end net debt to EBITDAX (as defined in the Amended Term Loan Agreement) must be no more than 3.0 to 1.0. Additionally, our debt service coverage ratio must be greater than 1.2 to 1.0 at each semi-annual review period. Certain of VAALCO's subsidiaries are contractually prohibited from making payments, loans or transferring assets to VAALCO or other affiliated entities. Specifically, under the Amended Term Loan Agreement, VAALCO Gabon S.A. could be restricted from transferring assets or making dividends, if the positive and negative covenants are not in compliance with the Amended Term Loan Agreement. We were in compliance with all financial covenants as of December 31, 2017.

Interest

Until June 29, 2016, under the terms of the original IFC credit facility, we paid commitment fees on the undrawn portion of the total commitment. Commitment fees had been equal to 1.5% of the unused balance of the senior tranche of $50.0 million and 2.3% of the unused balance of the subordinated tranche of $15.0 million when a commitment was available for utilization. With the execution of the Amended Term Loan Agreement with the IFC in June 2016, beginning on June 29, 2016, and continuing through March 14, 2017, commitment fees were equal to 2.3% of the undrawn term loan amount of $5.0 million. There are no further commitment fees owing after March 14, 2017.

The table below shows the components of the "Interest expense" line item of our consolidated statements of operations and the average effective interest rate, excluding commitment fees, on our borrowings:

	Year Ended December 31,		
	2017	2016	2015
	(in thousands)		
Interest incurred, including commitment fees	$ 997	$ 1,353	$ 1,496
Deferred finance cost amortization	369	319	304
Deferred finance cost write-off due to loan modification	—	869	—
Capitalized interest	—	—	(771)
Other interest not related to debt (a)	48	72	296
Interest expense, net	$ 1,414	$ 2,613	$ 1,325

Average effective interest rate, excluding commitment fees	6.72%	5.52%	4.09%

(a) The “Other interest not related to debt” line item includes interest income.

9. COMMITMENTS AND CONTINGENCIES

Litigation

Butcher settlement

On October 3, 2016, the Court approved a Stipulation and Order of Dismissal entered into by the parties in a stockholder class action lawsuit against the Company and all of its directors alleging that a previously terminated shareholder rights agreement, no longer in effect, and certain provisions of the former Chief Executive Officer’s and former Chief Financial Officer’s employment agreements securing change-in-control severance benefits were invalid under Delaware law, case number C.A. No. 12277-VCL, filed on April 29, 2016, in the Court. After the Company and its directors moved to dismiss the lawsuit, the Plaintiff Daniel Butcher agreed to dismiss the lawsuit as moot, and the Company agreed to settle Plaintiff’s application for an award of attorneys’ fees, all of which were covered by our directors and officers insurance as a covered claim.

McDonough litigation

On December 7, 2016, a lawsuit was filed against the Company alleging that a former worker on the Company’s oil and gas platforms off the coast of Gabon was terminated because of his age in violation of the Age Discrimination in Employment Act and the Texas Commission on Human Rights Act. The Plaintiff sought damages for lost wages and benefits as well as attorneys’ fees. The case was pending in the U.S. District Court for the Southern District of Texas styled as McDonough v. VAALCO Energy, Inc., No. 4:17-cv-

00361. In a February 2017 demand letter, the plaintiff made a demand for $361,000 to settle this claim. On June 22, 2017, the court entered a final order of dismissal, pursuant to the plaintiff's motion for voluntary dismissal, and entered final judgment in favor of the Company. This matter is now resolved, and had no material effect on our financial condition, results of operations or liquidity.

FPSO charter

In connection with the charter of the FPSO, we, as operator of the Etame Marin block, guaranteed all of the lease payments under the charter through its contract term, which expires in September 2020. At our election, the charter may be extended for two one-year periods beyond September 2020. We obtained guarantees from each of our partners for their respective shares of the payments. Our net share of the charter payment is 31.1%, or approximately $9.7 million per year. Although we believe the need for performance under the charter guarantee is remote, we recorded a liability of $0.5 million and $0.7 million as of December 31, 2017 and December 31, 2016, respectively, representing the guarantee's estimated fair value. The guarantee of the offshore Gabon FPSO lease has $85.2 million in remaining gross minimum obligations as of December 31, 2017.

Estimated future minimum obligations through the end of the FPSO charter are as follows:

(in thousands)	Full Charter Payment	VAALCO Net
Year		
2018	31,294	9,719
2019	31,294	9,719
2020	22,634	7,029
Total	$ 85,222	$ 26,467

The charter payment includes a $0.93 per barrel charter fee for production up to 20,000 barrels of oil per day and a $2.50 per barrel charter fee for those barrels produced in excess of 20,000 barrels of oil per day. VAALCO's net share of payments was $12.8 million, $11.2 million and $10.9 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Other lease obligations

In addition to the FPSO, we have operating lease obligations, as follows:

(in thousands)	Gross Obligation	VAALCO Net
Year		
2018	6,101	2,176
2019	407	407
2020	340	340
2021	—	—
2022	—	—
Thereafter	—	—
Total	$ 6,848	$ 2,923

We incurred rent expense of $2.4 million, $4.5 million and $4.3 million under operating leases for the years ended December 31, 2017, 2016 and 2015.

Rig commitment

In 2014, we entered into a long-term contract for the Constellation II drilling rig that was under a long-term contract for the multi-well development drilling campaign offshore Gabon. The campaign included the drilling of development wells and workovers of existing wells in the Etame Marin block. We began demobilization in January 2016 and released the drilling rig in February 2016, prior to the original July 2016 contract termination date, because we no longer intended to drill any wells in 2016 on our Etame Marin block offshore Gabon. In June 2016, we reached an agreement with the drilling contractor for us to pay $5.1 million net to VAALCO's interest for unused rig days under the contract. We paid this amount, plus the demobilization charges, in seven equal monthly installments, which began in July 2016 and ended in January 2017. The related expense was reported in the "Other operating expense" line item in our consolidated statement of operations for the year ended December 31, 2016.

Gabon domestic market obligation and other investment obligations

Under the terms of the Etame PSC, effective in April 2016, the consortium is required to provide to the local government refinery a volume of crude at a 15% discount to market price (the "Gabon DMO"). Prior to April 2016, the discount was 25%. The volume required to be furnished is the amount of the Etame Marin block production divided by total Gabon production times the volume of oil refined by the refinery per year. In 2017, we paid $1.2 million for our share of the 2016 obligation. In 2016, we paid $1.7 million for our share of the 2015 obligation. In 2015, we paid $2.3 million for our share of the 2014 obligation. We accrue an amount for the Gabon DMO based on management's best estimate of the volume of crude required, because the refinery does not publish throughput figures. The amount accrued at December 31, 2017, for our share of the 2017 obligation was $1.3 million. The amount accrued at December 31, 2016, for our share of the 2016 obligation was $1.1 million. These costs are cost recoverable under the terms of the

Etame PSC. Also, beginning in April 2016, the consortium is required to pay an additional 1% of revenues for provisions for diversified investments (“PID”) and for investments in hydrocarbons (“PIH”). The amount accrued at December 31, 2017, for our share of the 2017 obligation was $1.4 million. The amount accrued at December 31, 2016, for our share of the 2016 obligation was $0.4 million. 75% of PID and PIH costs are cost recoverable under the terms of the Etame PSC.

Abandonment funding

As part of securing the first of two five-year extensions to the Etame field production license to which we are entitled from the government of Gabon, we agreed to a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. The agreement was finalized in the first quarter of 2014 (effective 2011) providing for annual funding over a period of ten years at 12.14% of the total abandonment estimate for the first seven years, with annual payments for the remaining unfunded estimated costs spread over the last three years of the production license. The amounts paid will be reimbursed through the cost account and are non-refundable. The abandonment estimate used for this purpose is approximately $61.1 million ($19.0 million net to VAALCO) on an undiscounted basis. Through December 31, 2017, $34.8 million ($10.8 million net to VAALCO) on an undiscounted basis has been funded. This cash funding is reflected under “Other noncurrent assets” in the “Abandonment funding” line item of our consolidated balance sheet. Future changes to the anticipated abandonment cost estimate could change our asset retirement obligation and the amount of future abandonment funding payments.

Regulatory and Joint Interest Audits

We are subject to periodic routine audits by various government agencies in Gabon, including audits of our petroleum cost account, customs, taxes and other operational matters, as well as audits by other members of the contractor group under our joint operating agreements.

As of December 31, 2016, we had accrued $1.0 million net to VAALCO in the “Accrued liabilities and other” line item of our consolidated balance sheet for certain payroll taxes in Gabon which were not paid pertaining to labor provided to us over a number of years by a third-party contractor. While the payroll taxes were for individuals who were not our employees, we could be deemed liable for these expenses as the end user of the services provided. These liabilities were substantially resolved at the accrued amount in January 2017.

In 2016, the government of Gabon conducted an audit of our operations in Gabon, covering the years 2013 through 2014. We received the findings from this audit and responded to the audit findings in January 2017. Since providing our response, there have been changes in the Gabonese officials responsible for the audit. We are currently working with the newly appointed representatives to resolve the audit findings. We do not anticipate that the ultimate outcome of this audit will have a material effect on our financial condition, results of operations or liquidity.

In 2017, the government of Gabon conducted a tax audit of our Gabon subsidiary covering the years 2013 through 2016, and in December 2017, we received a report on their findings. We have evaluated the results of this audit, and have made an accrual of $0.5 million, net to VAALCO, for the estimated additional taxes along with penalties in the “Accrued liabilities and other” line item of our consolidated balance sheet.

At December 31, 2017, we had accrued $1.3 million net to VAALCO in the “Accrued liabilities and other” line item of our consolidated balance sheet for potential fees which may result from a customs audit.

Employment agreements

Our Chief Executive Officer and Chief Financial Officer have employment agreements which provide for payments of annual salary, incentive compensation and certain other benefits if their employment is terminated without cause.

10. DERIVATIVES AND FAIR VALUE

As of December 31, 2017, we had no derivative instruments outstanding. During the year ended December 31, 2017 and 2016, we had oil puts outstanding for anticipated sales volumes for the period from April 22, 2016 through December 31, 2017. Our put contracts are subject to agreements similar to a master netting agreement under which we have the legal right to offset assets and liabilities. At December 31, 2016, the fair value of all of the put contracts were an asset of $1.2 million.

The following table sets forth, by level within the fair value hierarchy and location on our consolidated balance sheets, the reported fair values of derivative instruments accounted for at fair value on a recurring basis:

Derivative Item	Balance Sheet Line	Carrying Value	Fair Value Measurements Using Level 1	Level 2	Level 3
		(in thousands)			
Crude oil puts	Prepayments and other				
Balance at December 31, 2017		$ —	$ —	$ —	$ —
Balance at December 31, 2016		$ 1,227	$ —	$ 1,227	$ —

The crude oil put contracts are measured at fair value using the Black's option pricing model. Level 2 observable inputs used in the valuation model include market information as of the reporting date, such as prevailing Brent crude futures prices, Brent crude futures commodity price volatility and interest rates. The determination of the put contract fair value includes the impact of the counterparty's non-performance risk.

To mitigate counterparty risk, we enter into such derivative contracts with creditworthy financial institutions deemed by management as competent and competitive market makers.

The following table sets forth the gain (loss) on derivative instruments on our consolidated statements of operations:

		Year Ended December 31,		
Derivative Item	Statement of Operations Line	2017	2016	2015
		(in thousands)		
Crude oil puts	Other, net	$ (1,032)	$ (1,711)	$ —

11. SHAREHOLDERS' EQUITY (DEFICIT)

Preferred stock – Authorized preferred stock consists of 500,000 shares with a par value of $25 per share. No shares of preferred stock were issued and outstanding as of December 31, 2017 or 2016.

Treasury stock – In the years ended December 31, 2017, 2016 and 2015, we withheld 26,000, 40,926 and 120,455 shares, respectively, in connection with cashless stock option exercises and restricted stock vestings to satisfy tax withholding obligations related to stock option exercises.

12. STOCK-BASED COMPENSATION AND OTHER BENEFIT PLANS

Our stock-based compensation has been granted under several stock incentive and long-term incentive plans. The plans authorize the Compensation Committee of our Board of Directors to issue various types of incentive compensation. Currently, we have issued stock options, restricted shares and SARs from the 2014 Long-Term Incentive Plan ("2014 Plan"). At December 31, 2017, 2,404,442 shares were authorized for future grants under this plan.

For each stock option granted, the number of authorized shares under the 2014 Plan will be reduced on a one-for-one basis. For each restricted share granted, the number of shares authorized under the 2014 Plan will be reduced by twice the number of restricted shares. We have no set policy for sourcing shares for option grants. Historically the shares issued under option grants have been new shares.

We record non-cash compensation expense related to stock-based compensation as general and administrative expense. For the years ended December 31, 2017, 2016 and 2015, non-cash compensation expense was $1.1 million, $0.2 million and $3.8 million, respectively, related to the issuance of stock options and restricted stock. Because we do not pay significant United States federal income taxes, no amounts were recorded for tax benefits.

Stock options

Stock options have an exercise price that may not be less than the fair market value of the underlying shares on the date of grant. In general, stock options granted to participants will become exercisable over a period determined by the Compensation Committee of our Board of Directors, which in the past has been a five year life, with the options vesting over a service period of up to five years. In addition, stock options will become exercisable upon a change in control, unless provided otherwise by the Compensation Committee. There were $39 thousand in cash proceeds received from the exercise of stock options in 2017. For 2016 and 2015 there were no cash proceeds received from the exercise of stock options. During 2017, options for 1,162,930 shares were granted to employees; these options vest over a three-year period, vesting in three equal parts on the first, second and third anniversaries after the date of grant. Options for 465,950 shares also were granted in 2017 to our non-employee directors, which were fully vested upon their grant.

We use the Black-Scholes model to calculate the grant date fair value of stock option awards. This fair value is then amortized to expense over the vesting period of the option. During 2017, 2016 and 2015, the weighted average assumptions shown below were used to calculate the weighted average grant date fair value of option grants. Because we have not paid cash dividends and do not anticipate paying cash dividends on the common stock in the foreseeable future, no expected dividend yield was input to the Black-Scholes model.

	Year Ended December 31,		
	2017	2016	2015
Weighted average exercise price - ($/share)	$ 0.99	$ 1.14	$ 4.41
Expected life in years	3.2	3.0	2.5
Average expected volatility	73 %	71 %	61 %
Risk-free interest rate	1.51 %	1.10 %	0.88 %
Weighted average grant date fair value - ($/share)	$ 0.49	$ 0.49	$ 1.65

Stock option activity for the year ended December 31, 2017 is provided below:

	Number of Shares Underlying Options (in thousands)	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2017	2,644	$ 3.92		
Granted	1,629	0.99		
Exercised	(37)	1.04		
Forfeited/expired	(1,639)	4.48		
Outstanding at December 31, 2017	2,597	1.77	3.53	$ —
Exercisable at December 31, 2017	1,506	2.30	3.28	$ —

The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option. The intrinsic value of stock options exercised in 2017 and 2015 was $0.0 million and $0.3 million, respectively. There were no exercises of stock options in 2016.

On February 28, 2018, the Company granted stock options for 494,941 shares with an exercise price of $0.86 per share.

As of December 31, 2017, unrecognized compensation cost related to outstanding stock options was $0.3 million which is expected to be recognized over a weighted average period of 1.5 years.

Restricted shares

Restricted stock granted to employees will vest over a period determined by the Compensation Committee which is generally a three-year period, vesting in three equal parts on the first three anniversaries following the date of the grant. Share grants to directors vest immediately and are not restricted. The following is a summary of activity in unvested restricted stock in 2017.

	Restricted Stock (in thousands)	Weighted Average Grant Price
Non-vested shares outstanding at January 1, 2017	252	$ 1.31
Awards granted	426	0.98
Awards vested	(297)	1.12
Awards forfeited	(41)	1.00
Non-vested shares outstanding at December 31, 2017	340	1.10

The total vest-date fair value of restricted stock awards which vested during 2017, 2016 and 2015 was $0.3 million, $0.6 million and $0.7 million, respectively. The weighted average grant date fair value per share of restricted stock awards was $0.98, $1.11 and $3.34 for the years ended December 31, 2017, 2016 and 2015, respectively.

On February 28, 2018, the Company issued 323,474 shares of service based restricted stock with a grant date fair value of $0.86 per share. The vesting of these shares is dependent upon the employee's continued service with the Company. The shares will vest in three equal parts over three years.

As of December 31, 2017, unrecognized compensation cost related to restricted stock totaled $0.2 million and is expected to be recognized over a weighted average period of 1.6 years.

Stock appreciation rights ("SARs")

SARs are granted under the VAALCO Energy, Inc. 2016 Stock Appreciation Rights Plan. A SAR is the right to receive a cash amount equal to the spread with respect to a share of common stock upon the exercise of the SAR. The spread is the difference between the SAR price per share specified in a SAR award on the date of grant (which may not be less than the fair market value of our common stock on the date of grant) and the fair market value per share on the date of exercise of the SAR. SARs granted to participants will become exercisable over a period determined by the Compensation Committee of our Board of Directors. In addition, SARs will become exercisable upon a change in control, unless provided otherwise by the Compensation Committee of our Board of Directors.

The 815,355 SARs granted in the three months ended March 31, 2016 vest over a three-year period with a life of 5 years and have a maximum spread of 300% of the $1.04 SAR price per share specified in a SAR award on the date of grant. The compensation expense related to these awards through December 31, 2016 was $25 thousand.

On February 28, 2018, 2,373,411 SARs were granted which vest over a three-year period with a life of 5 years and have a $0.86 SAR price per share specified in a SAR award on the date of grant.

For the year ended December 31, 2017, 1,049,528 SARs were granted, all having an exercise price of $1.20 per share. One-third of the SARs are to vest on or after the first anniversary of the grant date at such time when the market price per share of our common stock exceeds $1.30; one-third of the SARs are to vest on or after the second anniversary of the grant date at such time when the share price exceeds $1.50; and one-third of the SARs are to vest on or after the third anniversary of the grant date at such time when the share price exceeds $1.75. SARs granted in 2017 vest over a three year period with a life of 5 years; these SARs have a maximum spread equal to 300% of the $1.04 SAR price per share specified in a SAR award on the date of grant. The compensation expense related to these awards through December 31, 2017 was $0.1 million.

SAR activity for the year ended December 31, 2017 is provided below:

	Number of Shares Underlying SARs (in thousands)	Weighted Average Exercise Price Per Share	Term (in years)	Value (in thousands)
Outstanding at January 1, 2017	180	$ 1.04		
Granted	1,049	1.20		
Exercised	—	—		
Forfeited/expired	(153)	1.20		
Outstanding at December 31, 2017	1,076	1.17	3.21	$ —
Exercisable at December 31, 2017	60	1.04	3.21	$ —

Other benefit plans

We sponsor a 401(k) plan, with a company match feature, for our employees. Costs incurred in the years ended December 31, 2017, 2016 and 2015 for administering the plan, including the company match feature, were approximately $0.2 million, $0.3 million and $0.4 million, respectively.

13. INCOME TAXES

VAALCO and its domestic subsidiaries file a consolidated United States income tax return. Certain subsidiaries' operations are also subject to foreign income taxes.

On December 22, 2017, the United States government enacted the Tax Cuts and Jobs Act, commonly referred to as the Tax Reform Act. The Tax Reform Act includes significant changes to the U.S. income tax system including but not limited to: a federal corporate rate reduction from 35% to 21%; limitations on the deductibility of interest expense and executive compensation; repeal of the Alternative Minimum Tax (“AMT”); full expensing provisions related to business assets; creation of new minimum taxes such as the base erosion anti-abuse tax (“BEAT”) and Global Intangible Low Taxed Income (“GILTI”) tax; and the transition of U.S. international taxation from a worldwide tax system to a modified territorial tax system, which will result in a one time U.S. tax liability on those earnings which have not previously been repatriated to the U.S. (the “Transition Tax”). The provisional impacts of this legislation are outlined below:

- Beginning January 1, 2018, the U.S. corporate income tax rate will be 21%. The Company is required to recognize the impacts of this rate change on its deferred tax assets and liabilities in the period enacted. However, as the Company has a full valuation allowance on its net deferred tax asset, any deferred tax recognized due to the change in rate will be offset with a change in the valuation allowance. Therefore, there was no overall impact to the Financial Statements in 2017 due to this change in rate.
- The Tax Reform Act also repealed the corporate AMT for tax years beginning on or after January 1, 2018 and provides for existing alternative minimum tax credit carryovers to be refunded beginning in 2018. The Company has approximately $1.4 million in refundable credits, and it expects that a substantial portion will be refunded between 2018 and 2021. As such, most of the valuation allowance in place at the end of 2017 related to these credits has been released and a deferred tax asset of $1.3 million is reflected related to the expected benefit in future years.

- The Transition Tax on unrepatriated foreign earnings is a tax on previously untaxed accumulated and current earnings and profits ("E&P") of the Company's foreign subsidiaries. To determine the amount of the Transition Tax, the Company must determine, among other factors, the amount of post-1986 E&P of its foreign subsidiaries, as well as the amount of non-U.S. income taxes paid on such earnings. Based on the Company’s reasonable estimate of the Transition Tax, there is no provisional Transition Tax expense. The Company has not completed our accounting for the income tax effects of the transition tax and is continuing to evaluate this provision of the Tax Act.
- The Tax Reform Act creates a new requirement that GILTI income earned by foreign subsidiaries must be included currently in the gross income of the U.S. shareholder. Due to the complexity of the new GILTI tax rules, the Company is continuing to evaluate this provision of the Tax Act. Under U.S. GAAP, the Company is permitted to make an accounting policy election to either treat taxes due on future inclusions in U.S. taxable income related to GILTI as a current period expense when incurred or to factor such amounts into the Company's measurement of its deferred taxes. The Company has not yet completed its analysis of the GILTI tax rules and is not yet able to reasonably estimate the effect of this provision of the Tax Act or make an accounting policy election for the accounting treatment whether to record deferred taxes attributable to the GILTI tax. The Company has not recorded any amounts related to potential GILTI tax in the Company’s Financial Statements.

Other provisions in the legislation, such as interest deductibility and changes to executive compensation plans are not expected to have material implications to the Company’s Financial Statements. The income tax effects recorded in the Company’s Financial Statements as a result of the Tax Reform Act are provisional in accordance with the Securities and Exchange Commission’s Staff Accounting Bulletin number 118 “(SAB 118”) as the Company has not yet completed its evaluation of the impact of the new law. SAB 118 allows for a measurement period of up to one year after the enactment date of the Tax Reform Act to finalize the recording of the related tax impacts. The Company does not believe potential adjustments in future periods would materially impact the Company’s financial condition or results of operations.

Additionally, the Tax Reform Act may further limit the Company’s ability to utilize foreign tax credits in the future. The Tax Reform Act introduces a new credit limitation basket for foreign branch income. Income from foreign branches would now be allocated to this specific tax credit limitation basket which cannot offset income in other baskets of foreign income. Under the Tax Reform Act, foreign taxes imposed on the foreign branch profits will not offset U.S. non-branch related foreign source income. Additional guidance is needed to determine how this will impact the Company and any future utilization of foreign tax credit carryforwards.

In April 2017, the Company was notified by the U.S. Internal Revenue Service (“IRS”) that they would be conducting an audit of its 2014 U.S. federal tax return. The audit was concluded in 2018, and there were no significant findings as a result.

Provision for income taxes related to income (loss) from continuing operations consists of the following:

	Year Ended December 31,		
(in thousands)	2017	2016	2015
U.S. Federal:			
Current	$ —	$ —	$ —
Deferred	(1,260)	—	1,349
Foreign:			
Current	11,638	9,248	13,238
Deferred	—	—	—
Total	$ 10,378	$ 9,248	$ 14,587

The primary differences between the financial statement and tax bases of assets and liabilities resulted in deferred tax assets associated with continuing operations at December 31, 2017 and 2016 are as follows:

	As of December 31,	
(in thousands)	2017	2016
Deferred tax assets:		
Basis difference in fixed assets	$ 46,929	$ 89,016
Foreign tax credit carryforward	48,071	50,339
Alternative minimum tax credit carryover	1,349	1,349
U.S. federal net operating losses	22,490	30,230
Foreign net operating losses	26,371	25,543
Asset retirement obligations	4,234	6,514
Basis difference in receivables	1,331	1,824
Other	3,690	6,952
Total deferred tax assets	154,465	211,767
Valuation allowance	(153,205)	(211,767)
Net deferred tax assets	$ 1,260	$ —

Foreign tax credits will expire between the years 2018 and 2024. The alternative minimum tax credits do not expire, and foreign net operating losses (“NOLs”) are not subject to expiry dates. The NOL for our United Kingdom subsidiary can be carried forward indefinitely, while the NOLs for our Gabon subsidiaries are included in the respective subsidiaries’ cost oil accounts, which will be offset against future taxable revenues. The U.S federal NOL will expire between 2035 and 2037. The ability to utilize NOLs and other tax attributes could be subject to a limitation if the Company were to undergo an ownership change as defined in Section 382 of the Tax Code. Management assesses the available positive and negative evidence to estimate if existing deferred tax assets will be utilized. We do not anticipate utilization of the foreign tax credits prior to expiration nor do we expect to generate sufficient taxable income to utilize other deferred tax assets. On the basis of this evaluation, valuation allowances of $153.2 million,

$211.8 million and $210.7 million have been recorded as of December 31, 2017, 2016 and 2015, respectively. Valuation allowances reduce the deferred tax assets to the amount that is more likely than not to be realized.

As a result of the 2017 tax legislation enacted in the U.S., we expect to realize the benefit from our AMT credit carryforwards. The valuation allowance recorded related to AMT credits in previous periods was reversed in 2017 with the exception for a reserve for the possible sequestration of the credits. The $1.3 million reversal was recorded as a deferred income tax benefit during the fourth quarter of 2017.

The Company recognizes the financial statement benefit of a tax position only after determining that they are more likely than not to sustain the position following an audit. The Company believes that its income tax positions and deductions will be sustained on audit and therefore no reserves for uncertain tax positions have been established. Accordingly, no interest or penalties have been accrued as of December 31, 2017 and 2016. The Company's policy is to include interest and penalties related to unrecognized tax benefits as a component of income tax expense.

Income (loss) from continuing operations before income taxes is attributable as follows:

	Year Ended December 31,		
(in thousands)	2017	2016	2015
United States	$ (9,453)	$ (9,893)	$ (15,177)
Foreign	30,103	874	(90,790)
	$ 20,650	$ (9,019)	$ (105,967)

The reconciliation of income tax expense attributable to income (loss) from continuing operations to income tax on income (loss) from continuing operations at the U.S. statutory rate is as follows:

	Year Ended December 31,		
(in thousands)	2017	2016	2015
Tax provision computed at U.S. statutory rate	$ 7,228	$ (3,156)	$ (37,089)
Foreign taxes not offset in U.S. by foreign tax credits	6,775	6,319	(394)
Impact of Tax Reform Act	52,449	—	—
Effect of change in foreign statutory rates	—	2,394	3,014
Permanent differences	309	4,505	1,803
Foreign tax credit adjustments	2,394	—	—
Increase/(decrease) in valuation allowance	(58,777)	(802)	47,253
Other	—	(12)	—
Total income tax expense	$ 10,378	$ 9,248	$ 14,587

At December 31, 2017, 2016 and 2015, we were subject to foreign and U.S. federal taxes only, with no allocations made to state and local taxes. The following table summarizes the tax years that remain subject to examination by major tax jurisdictions:

Jurisdiction	Years
United States	2008-2017
Gabon	2013-2017

14. EARNINGS PER SHARE

Basic earnings per share ("EPS") is calculated using the average number of shares of common stock outstanding during each period. For the calculation of diluted shares, we assume that restricted stock is outstanding on the date of vesting, and we assume the issuance of shares from the exercise of stock options using the treasury stock method.

A reconciliation from basic to diluted shares follows:

	Year Ended December 31,		
	2017	2016	2015
	(in thousands)		
Basic weighted average shares outstanding	58,717	58,384	58,289
Effect of dilutive securities	3	—	—
Diluted weighted average shares outstanding	58,720	58,384	58,289
Stock options and unvested restricted stock grants excluded from dilutive calculation because they would be anti-dilutive	2,823	4,363	5,586

Because we recognized net losses for the years ended December 31, 2016 and 2015, there were no dilutive securities for these years.

15. SEGMENT INFORMATION

Our operations are based in Gabon, Equatorial Guinea and the U.S. Each of our three reportable operating segments is organized and managed based upon geographic location. Our Chief Executive Officer, who is the chief operating decision maker, and management review and evaluate the operation of each geographic segment separately primarily based on Operating income (loss). The operations of all segments include exploration for and production of hydrocarbons where commercial reserves have been found and developed. Revenues are based on the location of hydrocarbon production. Corporate and other is primarily corporate and operations support costs which are not allocated to the reportable operating segments.

Segment activity of continuing operations for the years ended December 31, 2017, 2016 and 2015 and long-lived assets and segment assets at December 31, 2017 and 2016 are as follows:

	Year Ended December 31, 2017				
(in thousands)	Gabon	Equatorial Guinea	U.S.	Corporate and Other	Total
Revenues-oil and natural gas sales	$ 76,978	$ —	$ 47	$ —	$ 77,025
Depreciation, depletion and amortization	6,196	—	1	260	6,457
Bad debt expense and other	452	—	—	—	452
Operating income (loss)	28,488	(122)	352	(8,767)	19,951
Other, net	3,142	15	—	(1,044)	2,113
Interest expense, net	(1,414)	—	—	—	(1,414)
Income tax expense (benefit)	11,638	—	—	(1,260)	10,378
Additions to property and equipment - accrual	1,576	—	—	126	1,702

	Year Ended December 31, 2016				
(in thousands)	Gabon	Equatorial Guinea	U.S.	Corporate and Other	Total
Revenues-oil and natural gas sales	$ 59,460	$ —	$ 324	$ —	$ 59,784
Depreciation, depletion and amortization	6,531	—	151	244	6,926
Impairment of proved properties	—	—	88	—	88
Bad debt expense and other	1,222	—	—	—	1,222
Other operating expense	8,853	—	—	—	8,853
Operating income (loss)	3,901	(384)	(72)	(7,836)	(4,391)
Other, net	(22)	(8)	—	(1,985)	(2,015)
Interest expense, net	(2,614)	—	—	1	(2,613)
Income tax expense	9,248	—	—	—	9,248
Additions to property and equipment - accrual	(4,242)	—	—	181	(4,061)

	Year Ended December 31, 2015				
(in thousands)	Gabon	Equatorial Guinea	U.S.	Corporate and Other	Total
Revenues-oil and natural gas sales	$ 79,947	$ —	$ 498	$ —	$ 80,445
Depreciation, depletion and amortization	32,125	—	633	240	32,998
Impairment of proved properties	78,080	—	3,242	—	81,322
Bad debt expense and other	2,968	—	—	—	2,968
Operating income (loss)	(87,243)	(1,342)	(4,366)	(10,155)	(103,106)
Other, net	(1,034)	(33)	—	(469)	(1,536)

Interest expense, net	(1,144)	—	—	(181)	(1,325)
Income tax expense	13,238	—	—	1,349	14,587
Additions to property and equipment - accrual	66,269	—	—	150	66,419

(in thousands)	Gabon	Equatorial Guinea	U.S.	Corporate and Other	Total
Long-lived assets from continuing operations:					
As of December 31, 2017	$ 12,638	$ 10,000	$ —	$ 583	$ 23,221
As of December 31, 2016	17,291	10,000	—	728	28,019

Information about our most significant customers

For the period from the second quarter of 2014 and through April 2015, our crude oil from Gabon was sold under a contract with The Vitol Group at the spot market for a fixed per barrel fee. Beginning in May 2015, we sold our crude oil production from Gabon under a term contract with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. The contracted purchasers were TOTSA Total Oil Trading SA (“Total”) for May through July of 2015 and Glencore Energy UK Ltd. (“Glencore”) for August of 2015 through December of 2017. The contract with Glencore U.K. ends in January 2019. Sales of oil to Glencore were approximately 100% of total revenues for 2017.

16. SUBSEQUENT EVENTS

The last lifting in 2017 was not completed until January 1, 2018 due to unsafe weather conditions. Net revenues of $6.5 million associated with net volumes delivered to the buyer on January 1, 2018 of 95,525 barrels will be reported as revenue in 2018. The 7.1% increase in the January 2018 lifting price over the December 2017 lifting price positively impacted January's revenue by $0.5 million.

17. SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Our unaudited quarterly results for years ended December 31, 2017 and 2016 were prepared in accordance with GAAP, and reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results. These adjustments are of a normal recurring nature. Quarterly income per share is based on the weighted average number of shares outstanding during the quarter. Because of changes in the number of shares outstanding during the quarters due to the exercise of stock options and issuance of common stock, the sum of quarterly earnings per share may not equal earnings per share for the year.

	Three Months Ended			
	March 31,	June 30,	September 30,	December 31,
	(in thousands of dollars except per share information)			
2017:				
Total revenues	$ 21,266	$ 20,425	$ 18,178	$ 17,156
Total operating costs and expenses	13,055	15,068	14,454	14,413
Operating income (loss)	8,148	5,587	3,721	2,495
Income (loss) from continuing operations	4,435	2,451	(148)	3,534
Loss from discontinued operations	(176)	(168)	(174)	(103)
Net income (loss)	4,259	2,283	(322)	3,431
Basis net income (loss) per share	$ 0.07	$ 0.04	$ (0.01)	$ 0.06
Diluted net income (loss) per share	$ 0.07	$ 0.04	$ (0.01)	$ 0.06

	Three Months Ended			
	March 31,	June 30,	September 30,	December 31,
	(in thousands of dollars except per share information)			

2016:				
Total revenues	$ 10,976	$ 18,847	$ 14,635	$ 15,326
Total operating costs and expenses	24,509	14,232	10,919	14,249
Operating income (loss)	(13,515)	4,615	3,690	819
Income (loss) from continuing operations	(15,430)	(498)	1,016	(3,355)
Loss from discontinued operations	7,806	(20)	(15,783)	(286)
Net income (loss)	(7,624)	(518)	(14,767)	(3,641)
Basis net income (loss) per share	$ (0.13)	$ (0.01)	$ (0.25)	$ (0.06)
Diluted net income (loss) per share	$ (0.13)	$ (0.01)	$ (0.25)	$ (0.06)

SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES (UNAUDITED)

This supplemental information is presented in accordance with certain provisions of ASC Topic 932 – Extractive Activities- Oil and Natural Gas. The geographic areas reported are the United States (North America), which includes our producing properties in the state of Texas, and International, which includes our producing properties offshore Gabon (Africa).

Costs Incurred for Acquisition, Exploration and Development Activities

	Year Ended December 31,		
	2017	2016	2015
Costs incurred during the year:	(in thousands)		
International:			
Exploration costs - capitalized	$ —	$ —	$ —
Exploration costs - expensed	7	5	170
Acquisition of properties	—	5,754	—
Development costs	—	—	60,397
Total	$ 7	$ 5,759	$ 60,567

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

Capitalized costs pertain to our producing activities in Gabon and the U.S and to undeveloped leasehold in Gabon, Equatorial Guinea and the U.S.

	December 31,	
	2017	2016
Capitalized costs:	(in thousands)	
Properties not being amortized	$ 15,668	$ 15,980
Properties being amortized (1)	389,935	389,231
Total capitalized costs	$ 405,603	$ 405,211
Less accumulated depletion, amortization and impairment	(384,014)	(379,473)
Net capitalized costs	$ 21,589	$ 25,738

(1) Includes $11.0 million and $10.3 million asset retirement cost in 2017 and 2016, respectively.

Results of Operations for Oil and Natural Gas Producing Activities

	International			United States		
	Year Ended December 31,			Year Ended December 31,		
	2017	2016	2015	2017	2016	2015
	(in thousands)					
Crude oil and natural gas sales	$ 76,978	$ 59,460	$ 79,947	$ 47	$ 324	$ 498
Production costs and other expense (1)	(41,558)	(38,160)	(42,399)	(26)	(166)	(171)
Depreciation, depletion, amortization	(6,196)	(6,531)	(32,125)	(1)	(151)	(633)
Exploration expenses	(7)	(5)	(9,159)	—	—	(1,250)
Impairment of proved properties	—	—	(78,080)	—	(88)	(3,242)
Other operating expense	—	(8,853)	—	—	—	—
Bad debt expense	(452)	(1,222)	(2,700)	—	—	—
Income tax	(11,638)	(9,248)	(13,238)	1,260	—	(1,349)
Results from oil and natural gas producing activities	$ 17,127	$ (4,559)	$ (97,754)	$ 1,280	$ (81)	$ (6,147)

(1)Includes local general and administrative expenses, but excludes corporate general and administrative expenses and allocated corporate overhead.

Estimated Quantities of Proved Reserves

The estimation of net recoverable quantities of crude oil and natural gas is a highly technical process which is based upon several underlying assumptions that are subject to change. See “Item 1A. Risk Factors” and “Item 7. Management’s Discussion and Analysis of Financial Condition, Cash Flows and Liquidity – Critical Accounting Estimates – Estimated Quantities of Net Reserves”. For a discussion of our reserve estimation process, including internal controls, see “Item 1. Business – Reserves”.

Proved reserves:	Oil (MBbls)	Natural Gas (MMCF)
Balance at January 1, 2015	8,260	1,406
Production	(1,659)	(181)
Revisions of previous estimates	(3,746)	(172)
Balance at December 31, 2015	2,855	1,053
Production	(1,518)	(124)
Purchases of minerals in place	308	—
Sales of minerals in place	(12)	(929)
Revisions of previous estimates	1,009	—
Balance at December 31, 2016	2,642	—
Production	(1,518)	—
Revisions of previous estimates	1,925	—
Balance at December 31, 2017	3,049	—

Proved developed reserves:	Oil (MBbls)	Natural Gas (MMCF)
Balance at January 1, 2015	3,224	1,406
Balance at December 31, 2015	2,855	1,053
Balance at December 31, 2016	2,642	—
Balance at December 31, 2017	3,049	—

Our proved developed reserves are located offshore Gabon. The upward revision of the previous estimates in 2017 was primarily a result of improved well performance and to a lesser degree the higher average crude oil prices. In 2016, reserves increased as a result of estimated proved reserve quantities related to our acquisition of the Sojitz working interest in Etame Marin block (308 MBbl) as well as upward revisions to our estimated proved reserve quantities as a result of cost cutting efforts that had the impact of driving down operating cost projections and extending economic limits, demonstration of the effectiveness of deploying lower cost hydraulic workover units to conduct workovers during 2016 and success in production optimization produced better-than-forecasted results from the prior year's development program (1,575 MBbl). These positive developments were somewhat offset by the effects of an 18% reduction in the average price used to determine reserves in 2016 versus 2015 (566 MBbl). The net negative revisions of previous estimates in 2015 were primarily a result of the loss of 3.5 years of production due to lower oil prices (2,705 MBOE) and the removal of sour reserves (1,440 MBbl), partially offset by positive revisions due to the performance of wells drilled in the 2014-2015 drilling campaign exceeding expectations (370 MBbl).

We maintain a policy of not booking proved reserves on discoveries until such time as a development plan has been prepared for the discovery indicating that the development well will be drilled within five years from the date of its initial booking. Additionally, the development plan is required to have the approval of our partners in the discovery. Furthermore, if a government agreement that the reserves are commercial is required to develop the field, this approval must have been received prior to booking any reserves.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil Reserves

The information that follows has been developed pursuant to procedures prescribed GAAP and uses reserve and production data estimated by independent petroleum consultants. The information may be useful for certain comparison purposes, but should not be solely relied upon in evaluating us or our performance.

In accordance with the guidelines of the SEC, our estimates of future net cash flow from our properties and the present value thereof are made using oil and natural gas contract prices using a twelve month average of beginning of month prices and are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. The future cash flows are also based on costs in existence at the dates of the projections, excluding Gabon royalties, and the interests of other consortium members. Future production costs do not include overhead charges allowed under joint operating agreements or headquarters general and administrative overhead expenses. However, all future costs related to future property abandonment when the wells become uneconomic to produce are included in future development costs for purposes of calculating the standardized measure of discounted net cash flows.

	International			United States			Total		
(In thousands)	2017	2016	2015	2017	2016	2015	2017	2016	2015
Future cash inflows	$ 165,341	$ 106,583	$ 140,190	$ —	$ —	$ 3,086	$ 165,341	$ 106,583	$ 143,276
Future production costs	(108,387)	(71,260)	(81,973)	—	—	(1,644)	(108,387)	(71,260)	(83,617)
Future development costs (1)	(8,803)	(10,887)	(10,900)	—	—	(259)	(8,803)	(10,887)	(11,159)
Future income tax expense	(24,798)	(16,346)	(21,598)	—	—	—	(24,798)	(16,346)	(21,598)
Future net cash flows	23,353	8,090	25,719	—	—	1,183	23,353	8,090	26,902
Discount to present value at 10% annual rate	(863)	1,351	491	—		(252)	(863)	1,351	239
Standardized measure of discounted future net cash flows	$ 22,490	$ 9,441	$ 26,210	$ —	$ —	$ 931	$ 22,490	$ 9,441	$ 27,141

(1)Includes costs expected to be incurred to abandon the properties.

International income taxes represent amounts payable to the Government of Gabon on profit oil as final payment of corporate income taxes, and domestic income taxes (including other expenses treated as taxes), and domestic income taxes represent amounts payable for severance and ad-valorem taxes in Texas.

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Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth the changes in standardized measure of discounted future net cash flows as follows:

	Year Ended December 31,		
	2017	2016	2015
	(in thousands)		
Balance at beginning of period	$ 9,441	$ 27,141	$ 149,387
Sales of oil and natural gas, net of production costs	(37,328)	(22,198)	(40,349)
Net changes in prices and production costs	35,257	(25,958)	(146,536)
Revisions of previous quantity estimates	18,743	19,558	(104,158)
Purchases	—	3,400	—
Divestitures of reserves	—	(835)	—
Changes in estimated future development costs	(692)	—	(15,604)
Development costs incurred during the period	2,298	—	60,004
Accretion of discount	2,482	4,657	27,312
Net change of income taxes	(7,432)	4,052	104,303
Change in production rates (timing) and other	(279)	(376)	(7,218)
Balance at end of period	$ 22,490	$ 9,441	$ 27,141

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas sales prices may all differ from those assumed in these estimates. The standardized measure of discounted future net cash flow should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties. The information set forth in the foregoing tables includes revisions for certain reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of a decrease (or increase) in the projected economic life of such properties resulting from changes in product prices. Moreover, crude oil amounts shown for Gabon are recoverable under a service contract and the reserves in place at the end of the contract period remain the property of the Gabon government.

In accordance with the current guidelines of the U.S. Securities and Exchange Commission ("SEC"), estimates of future net cash flow from our properties and the present value thereof are made using an unweighted, arithmetic average of the first-day-of-the-month price for each of the 12 months of the year adjusted for quality, transportation fees and market differentials. Such prices are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For 2017, the average of such prices reflected a 33% increase during the year and were $53.49 per Bbl for crude oil from Gabon when compared to the average of such prices for 2016 of $40.35 per Bbl for crude oil from Gabon.

Under the PSC in Gabon, the Gabonese government is the owner of all oil and natural gas mineral rights. The right to produce the oil and natural gas is stewarded by the Directorate Generale de Hydrocarbures and the PSC was awarded by a decree from the State. Pursuant to the contract, the Gabon government receives a fixed royalty rate of 13%. Originally, under the PSC, Gabonese government was not anticipated to take physical delivery of its allocated production. Instead, we were authorized to sell the Gabonese government's share of production and remit the proceeds to the Gabonese government. Beginning in February 2018, the Gabonese government elected to take physical delivery of its allocated production volumes for "profit oil" (see discussion below).

The consortium maintains a Cost Account, which entitles it to receive 70% of the production remaining after deducting the 13% royalty so long as there are amounts remaining in the Cost Account ("Cost Recovery"). At December 31, 2017, there was $97.6 million in the cost account net to our interest. As payment of corporate income taxes, the consortium pays the government an allocation of the remaining "profit oil" production from the contract area ranging from 50% to 60% of the oil remaining after deducting the royalty and Cost Recovery. The percentage of "profit oil" paid to the government as tax is a function of production rates. However, when the Cost Account becomes substantially recovered, we only recover ongoing operating expenses and new project capital expenditures, resulting in a higher tax rate. Also because of the nature of the Cost Account, decreases in oil prices result in a higher number of barrels required to recover costs, therefore at higher oil prices, our net reserves after taxes would decrease, but at lower prices our Cost Recovery barrels increase.

The Etame PSC allows for the carve-out of development areas which include all producing fields in the Etame Marin block. The Etame development area has a term of 20 years and will expire in 2021. The Avouma/South Tchibala field development area has a term of 20 years and will expire in 2025. The Ebouri field development area has a term of 20 years and will expire in 2026. The balance of the Etame Marin block comprises the exploration area, which expired in July 2014. This compares to the economic end date of reserves under the current reserve report prepared by our independent reserve engineering firm of November 2020.

The Mutamba Iroru PSC entitles us to receive 70% of any future production remaining after deducting the royalty so long as there are amounts remaining in the Cost Account. The Mutamba Iroru PSC provides for all commercial discoveries to be reclassified into a development area with a term of twenty years. At December 31, 2017, we have no proved reserves related to the Mutamba Iroru block.

The PSC for Block P in Equatorial Guinea entitles us to receive up to 70% of any future production after royalty deduction so long as there are amounts remaining in the Cost Account. Royalty rates are 10-16% depending on production rates. The consortium pays the government an allocation of the remaining “profit oil” production from the contract area ranging from 10% to 60% of the oil remaining after deducting the royalty and Cost Recovery. The percentage of “profit oil” paid to the government as tax is a function of cumulative production. In addition, Equatorial Guinea imposes a 25% income tax on net profits. The Block P PSC provides for a discovery to be reclassified into a development area with a term of 25 years. At December 31, 2017, we have no proved reserves related to Block P in Equatorial Guinea.

SCHEDULE I — PARENT COMPANY FINANCIAL STATEMENTS

VAALCO ENERGY, INC.

CONDENSED UNCONSOLIDATED BALANCE SHEETS

(in thousands, except number of shares and par value amounts)

	December 31,	
	2017	2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 576	$ 1,038
Receivables:		
Other	101	21
Prepayments and other	599	1,696
Total current assets	1,276	2,755
Equipment and other	1,304	1,225
	1,304	1,225
Accumulated depreciation, depletion and amortization	(721)	(497)
Net property and equipment	583	728
Other noncurrent assets:		
Restricted cash	50	—
Deferred tax asset	1,260	—
Investment in subsidiaries	8,091	—
Total assets	$ 11,260	$ 3,483
LIABILITIES AND EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	$ 98	$ 310
Accrued liabilities and other	873	1,024
Total current liabilities	971	1,334
Losses in excess of investment in subsidiaries	—	2,507
Total liabilities	971	3,841
Commitments and contingencies		
VAALCO Energy Inc. shareholders' equity (deficit):		
Common stock, $0.10 par value; 100,000,000 shares authorized, 66,443,971 and 66,109,565 shares issued, 58,862,876 and 58,554,470 shares outstanding	6,644	6,611
Additional paid-in capital	71,251	70,268
Less treasury stock, 7,581,095 and 7,555,095 shares at cost	(37,953)	(37,933)
Accumulated deficit	(29,653)	(39,304)
Total equity (deficit)	10,289	(358)
Total liabilities and equity (deficit)	$ 11,260	$ 3,483

See accompanying notes to the condensed unconsolidated financial statements.

VAALCO ENERGY, INC.

STATEMENTS OF CONDENSED UNCONSOLIDATED OPERATIONS

(in thousands)

	Year Ended December 31,		
	2017	2016	2015
Operating costs and expenses:			
Depreciation, depletion and amortization	$ 260	$ 244	$ 240
General and administrative expense	8,489	7,935	7,550
Shareholder matters	—	(332)	2,372
Total operating costs and expenses	8,749	7,847	10,162
Other operating income (expense), net	(12)	16	—
Operating loss	(8,761)	(7,831)	(10,162)
Other income (expense):			
Interest expense, net	—	(2)	(181)
Other, net	(1,044)	(1,985)	(469)
Equity in subsidiary earnings (losses)	18,196	(16,732)	(146,495)
Total other income (expense)	17,152	(18,719)	(147,145)
Income before income taxes	8,391	(26,550)	(157,307)
Income tax (benefit) expense	(1,260)	—	1,349
Net income (loss)	$ 9,651	$ (26,550)	$ (158,656)

See accompanying notes to the condensed unconsolidated financial statements.

VAALCO ENERGY, INC.

STATEMENTS OF CONDENSED UNCONSOLIDATED CASH FLOWS

(in thousands of dollars)

	Year Ended December 31,		
	2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ 9,651	$ (26,550)	$ (158,656)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	260	244	240
Other operating loss, net	12	—	—
Deferred tax asset	(1,260)	—	1,349
Stock-based compensation	1,098	192	3,810
Equity in (earnings) losses from subsidiaries	(18,196)	16,732	146,495
Commodity derivatives net (gain) loss	1,032	—	—
Cash settlements received on matured commodity derivative contracts	195	—	—
Change in operating assets and liabilities:			
Other receivables	(80)	(21)	293
Prepayments and other	(130)	(955)	(236)
Accounts payable	(212)	(658)	753
Accrued liabilities and other	(272)	(1,855)	517
Net cash used in operating activities	(7,902)	(12,871)	(5,435)
CASH FLOWS FROM INVESTING ACTIVITIES			
Investment in subsidiaries	—	—	(7,044)
Return of investment in subsidiaries	7,598	12,556	—
Decrease in restricted cash	(50)	1,582	8,418
Property and equipment expenditures	(127)	(178)	(160)
Net cash provided by investing activities	7,421	13,960	1,214
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the issuances of common stock	39	—	441
Treasury shares	(20)	(51)	—

Net cash provided by (used in) financing activities	19	(51)	441
NET CHANGE IN CASH AND CASH EQUIVALENTS	(462)	1,038	(3,780)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	1,038	—	3,780
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 576	$ 1,038	$ —

See accompanying notes to the condensed unconsolidated financial statements.

Notes to Condensed Unconsolidated Financial Statements

Note 1- The condensed financial statements of VAALCO Energy, Inc. (the “Parent Company”) have been prepared pursuant to Rule 5-04 of Regulation S-X of the Securities Exchange Act of 1934, as amended, because certain of VAALCO’s subsidiaries are contractually prohibited from making payments, loans or transferring assets to the Parent Company or other affiliated entities. Specifically, under the terms of our IFC Term Loan, VAALCO Gabon S.A. could be restricted from transferring assets or making dividends, if the positive and negative covenants are not in compliance with the Term Loan. The restricted net assets associated with each of these entities exceed 25% of the consolidated net assets of VAALCO Energy, Inc. as of December 31, 2017 and 2016.

For purposes of these financial statements, the Parent Company’s investments in wholly owned subsidiaries are accounted for under the equity method. Under this method, the accounts of the subsidiaries are not consolidated. The investments in and advances to subsidiaries are recorded in the unconsolidated balance sheets. The Parent Company’s share of income (loss) from operations of the subsidiaries is reported as equity in subsidiary earnings, net of tax, in its unconsolidated statements of operations. These statements should be read in conjunction with the consolidated financial statements and notes thereto, included in Part II, Item 8 of in this Annual Report on Form 10-K.

The Parent Company and certain of its subsidiaries file a consolidated tax return for U.S. federal income taxes. The amount of income tax expense for the Parent Company financial statements represents the amount attributable to the U.S. federal and state tax jurisdictions. Income tax expense for foreign jurisdictions has been included in the applicable subsidiary’s results.