Kosmos Energy Ltd.
Form 10-K
February 26, 2018
Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10 K
(Mark
One)

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

For the fiscal year ended December 31, 2017

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

For the transition period from to
Commission file number: 001 35167
Kosmos Energy Ltd.
(Exact name of registrant as specified in its charter)

Bermuda	98 0686001
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
Clarendon House	
2 Church Street	HM 11
Hamilton, Bermuda	(Zip Code)
(Address of principal executive offices)	

Registrant's telephone number, including area code: +1 441 295 5950
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered:
Common Shares $0.01 par value	New York Stock Exchange
	London Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No ý
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 ý No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10 K or any amendment to this Form 10 K. ý
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b 2 of the Exchange Act.
Non accelerated filer

Large accelerated filer	Accelerated filer	(Do not check if a smaller reporting company)	Smaller reporting company	Emerging growth company

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

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

The aggregate market value of the voting and non voting common shares held by non affiliates, based on the per share closing price of the registrant's common shares as of the last business day of the registrant's most recently completed second fiscal quarter was $1,462,148,287.

The number of the registrant's Common Shares outstanding as of February 16, 2018 was 395,706,528.

DOCUMENTS INCORPORATED BY REFERENCE

Part III, Items 10 14, is incorporated by reference from the Proxy Statement for the Annual Meeting of Shareholders which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2017.

Certain exhibits previously filed with the Securities and Exchange Commission are incorporated by reference into Part IV of this report.

Table of Contents

TABLE OF CONTENTS

Unless otherwise stated in this report, references to "Kosmos," "we," "us" or "the company" refer to Kosmos Energy Ltd. and its subsidiaries. We have provided definitions for some of the industry terms used in this report in the "Glossary and Selected Abbreviations" beginning on page 2.

		Page
	Glossary and Selected Abbreviations	3
	Cautionary Statement Regarding Forward Looking Statements	6
	PART I	
Item 1.	Business	8
Item 1A.	Risk Factors	37
Item 1B.	Unresolved Staff Comments	60
Item 2.	Properties	60
Item 3.	Legal Proceedings	60
Item 4.	Mine Safety Disclosures	60
	PART II	
Item 5.	Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	61
Item 6.	Selected Financial Data	63
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	65
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	84
Item 8.	Financial Statements and Supplementary Data	87
Item 9.	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	128
Item 9A.	Controls and Procedures	128
Item 9B.	Other Information	128
	PART III	
Item 10.	Directors, Executive Officers and Corporate Governance	130
Item 11.	Executive Compensation	130
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	130
Item 13.	Certain Relationships and Related Transactions, and Director Independence	130
Item 14.	Principal Accounting Fees and Services	130
	PART IV	
Item 15.	Exhibits, Financial Statement Schedules	131
Item 16.	Form 10-K Summary	135

Table of Contents

KOSMOS ENERGY LTD.

GLOSSARY AND SELECTED ABBREVIATIONS

The following are abbreviations and definitions of certain terms that may be used in this report. Unless listed below, all defined terms under Rule 4 10(a) of Regulation S X shall have their statutorily prescribed meanings.

"2D seismic data"	Two dimensional seismic data, serving as interpretive data that allows a view of a vertical cross section beneath a prospective area.
"3D seismic data"	Three dimensional seismic data, serving as geophysical data that depicts the subsurface strata in three dimensions. 3D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic data.
"API"	A specific gravity scale, expressed in degrees, that denotes the relative density of various petroleum liquids. The scale increases inversely with density. Thus lighter petroleum liquids will have a higher API than heavier ones.
"ASC"	Financial Accounting Standards Board Accounting Standards Codification.
"ASU"	Financial Accounting Standards Board Accounting Standards Update.
"Barrel" or "Bbl"	A standard measure of volume for petroleum corresponding to approximately 42 gallons at 60 degrees Fahrenheit.
"BBbl"	Billion barrels of oil.
"BBoe"	Billion barrels of oil equivalent.
"Bcf"	Billion cubic feet.
"Boe"	Barrels of oil equivalent. Volumes of natural gas converted to barrels of oil using a conversion factor of 6,000 cubic feet of natural gas to one barrel of oil.
"Boepd"	Barrels of oil equivalent per day.
"Bopd"	Barrels of oil per day.
"Bwpd"	Barrels of water per day.
"Debt cover ratio"	The "debt cover ratio" is broadly defined, for each applicable calculation date, as the ratio of (x) total long term debt less cash and cash equivalents and restricted cash, to (y) the aggregate EBITDAX (see below) of the Company for the previous twelve months.
"Developed acreage"	The number of acres that are allocated or assignable to productive wells or wells capable of production.
"Development"	The phase in which an oil or natural gas field is brought into production by drilling development wells and installing appropriate production systems.
"Dry hole"	A well that has not encountered a hydrocarbon bearing reservoir expected to produce in commercial quantities.
"EBITDAX"	Net income (loss) plus (i) exploration expense, (ii) depletion, depreciation and amortization expense, (iii) equity based compensation expense, (iv) unrealized (gain) loss on commodity derivatives (realized losses are deducted and realized gains are added back), (v) (gain) loss on sale of oil and gas properties, (vi) interest (income) expense, (vii) income taxes, (viii) loss on extinguishment of debt, (ix) doubtful accounts expense and (x) similar other material items which management believes affect the comparability of operating results. The Facility EBITDAX definition includes 50% of the EBITDAX adjustments of Kosmos-Trident International Petroleum Inc.
"E&P"	Exploration and production.
"FASB"	Financial Accounting Standards Board.
"Farm in"	An agreement whereby a party acquires a portion of the participating interest in a block from the owner of such interest, usually in return for cash and for taking on a portion of the drilling costs of one or more specific wells or other performance by the assignee as a condition of the assignment.
"Farm out"	An agreement whereby the owner of the participating interest agrees to assign a portion of its participating interest in a block to another party for cash and/or for the assignee taking on a portion of the drilling costs of one or more specific wells and/or other work as a condition of the assignment.

Table of Contents

"Field life cover ratio"	The "field life cover ratio" is broadly defined, for each applicable forecast period, as the ratio of (x) the forecasted net present value of net cash flow through depletion plus the net present value of the forecast of certain capital expenditures incurred in relation to the Ghana and Equatorial Guinea assets, to (y) the aggregate loan amounts outstanding under the Facility.
"FPSO"	Floating production, storage and offloading vessel.
"Interest cover ratio"	The "interest cover ratio" is broadly defined, for each applicable calculation date, as the ratio of (x) the aggregate EBITDAX (see above) of the Company for the previous twelve months, to (y) interest expense less interest income for the Company for the previous twelve months.
"Loan life cover ratio"	The "loan life cover ratio" is broadly defined, for each applicable forecast period, as the ratio of (x) net present value of forecasted net cash flow through the final maturity date of the Facility plus the net present value of forecasted capital expenditures incurred in relation to the Ghana and Equatorial Guinea assets, to (y) the aggregate loan amounts outstanding under the Facility.
"LNG"	Liquefied natural gas.
"MBbl"	Thousand barrels of oil.
"Mcf"	Thousand cubic feet of natural gas.
"Mcfpd"	Thousand cubic feet per day of natural gas.
"MMBbl"	Million barrels of oil.
"MMBoe"	Million barrels of oil equivalent.
"MMcf"	Million cubic feet of natural gas.
"MMcfd"	Million cubic feet per day of natural gas.
"Natural gas liquid" or "NGL"	Components of natural gas that are separated from the gas state in the form of liquids. These include propane, butane, and ethane, among others.
"Petroleum contract"	A contract in which the owner of hydrocarbons gives an E&P company temporary and limited rights, including an exclusive option to explore for, develop, and produce hydrocarbons from the lease area.
"Petroleum system"	A petroleum system consists of organic material that has been buried at a sufficient depth to allow adequate temperature and pressure to expel hydrocarbons and cause the movement of oil and natural gas from the area in which it was formed to a reservoir rock where it can accumulate.
"Plan of development" or "PoD"	A written document outlining the steps to be undertaken to develop a field.
"Productive well"	An exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.
"Prospect(s)"	A potential trap that may contain hydrocarbons and is supported by the necessary amount and quality of geologic and geophysical data to indicate a probability of oil and/or natural gas accumulation ready to be drilled. The five required elements (generation, migration, reservoir, seal and trap) must be present for a prospect to work and if any of these fail neither oil nor natural gas may be present, at least not in commercial volumes.
"Proved reserves"	Estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be economically recoverable in future years from known reservoirs under existing economic and operating conditions, as well as additional reserves expected to be obtained through confirmed improved recovery techniques, as defined in SEC Regulation S X 4 10(a)(2).
"Proved developed reserves"	Those proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.
"Proved undeveloped reserves"	Those proved reserves that are expected to be recovered from future wells and facilities, including future improved recovery projects which are anticipated with a high degree of certainty in reservoirs which have previously shown favorable response to improved recovery projects.

"Shelf margin"	The path created by the change in direction of the shoreline in reaction to the filling of a sedimentary basin.
"Stratigraphy"	The study of the composition, relative ages and distribution of layers of sedimentary rock.

Table of Contents

“Stratigraphic trap”	A stratigraphic trap is formed from a change in the character of the rock rather than faulting or folding of the rock and oil is held in place by changes in the porosity and permeability of overlying rocks.
“Structural trap”	A topographic feature in the earth’s subsurface that forms a high point in the rock strata. This facilitates the accumulation of oil and gas in the strata.
“Structural stratigraphic trap”	A structural stratigraphic trap is a combination trap with structural and stratigraphic features.
“Submarine fan”	A fan shaped deposit of sediments occurring in a deep water setting where sediments have been transported via mass flow, gravity induced, processes from the shallow to deep water. These systems commonly develop at the bottom of sedimentary basins or at the end of large rivers.
“Three way fault trap”	A structural trap where at least one of the components of closure is formed by offset of rock layers across a fault.
“Trap”	A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate.
“Undeveloped acreage”	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains discovered resources.

Table of Contents

Cautionary Statement Regarding Forward Looking Statements

This annual report on Form 10 K contains estimates and forward looking statements, principally in “Item 1. Business,” “Item 1A. Risk Factors” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.” Our estimates and forward looking statements are mainly based on our current expectations and estimates of future events and trends, which affect or may affect our businesses and operations. Although we believe that these estimates and forward looking statements are based upon reasonable assumptions, they are subject to several risks and uncertainties and are made in light of information currently available to us. Many important factors, in addition to the factors described in our annual report on Form 10 K, may adversely affect our results as indicated in forward looking statements. You should read this annual report on Form 10 K and the documents that we have filed as exhibits hereto completely and with the understanding that our actual future results may be materially different from what we expect.

Our estimates and forward looking statements may be influenced by the following factors, among others:

- our ability to find, acquire or gain access to other discoveries and prospects and to successfully develop and produce from our current discoveries and prospects;
- uncertainties inherent in making estimates of our oil and natural gas data;
- the successful implementation of our and our block partners’ prospect discovery and development and drilling plans;
- projected and targeted capital expenditures and other costs, commitments and revenues;
- termination of or intervention in concessions, rights or authorizations granted by the governments of Cote d'Ivoire, Equatorial Guinea, Ghana, Mauritania, Morocco, Sao Tome and Principe, Senegal or Suriname (or their respective national oil companies) or any other federal, state or local governments or authorities, to us;
- our dependence on our key management personnel and our ability to attract and retain qualified technical personnel;
- the ability to obtain financing and to comply with the terms under which such financing may be available;
- the volatility of oil and natural gas prices;
- the availability, cost, function and reliability of developing appropriate infrastructure around and transportation to our discoveries and prospects;
- the availability and cost of drilling rigs, production equipment, supplies, personnel and oilfield services;
- other competitive pressures;
- potential liabilities inherent in oil and natural gas operations, including drilling and production risks and other operational and environmental risks and hazards;
- current and future government regulation of the oil and gas industry or regulation of the investment in or ability to do business with certain countries or regimes;
- cost of compliance with laws and regulations;
- changes in environmental, health and safety or climate change or greenhouse gas (“GHG”) laws and regulations or the implementation, or interpretation, of those laws and regulations;
- adverse effects of sovereign boundary disputes in the jurisdictions in which we operate;
- environmental liabilities;
- geological, geophysical and other technical and operations problems including drilling and oil and gas production and processing;
- military operations, civil unrest, outbreaks of disease, terrorist acts, wars or embargoes;
- the cost and availability of adequate insurance coverage and whether such coverage is enough to sufficiently mitigate potential losses and whether our insurers comply with their obligations under our coverage agreements;

Table of Contents

- our vulnerability to severe weather events;
- our ability to meet our obligations under the agreements governing our indebtedness;
- the availability and cost of financing and refinancing our indebtedness;
- the amount of collateral required to be posted from time to time in our hedging transactions, letters of credit and other secured debt;
- the result of any legal proceedings, arbitrations, or investigations we may be subject to or involved in;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks; and
- other risk factors discussed in the "Item 1A. Risk Factors" section of this annual report on Form 10 K.

The words "believe," "may," "will," "aim," "estimate," "continue," "anticipate," "intend," "expect," "plan" and similar words a to identify estimates and forward looking statements. Estimates and forward looking statements speak only as of the date they were made, and, except to the extent required by law, we undertake no obligation to update or to review any estimate and/or forward looking statement because of new information, future events or other factors. Estimates and forward looking statements involve risks and uncertainties and are not guarantees of future performance. As a result of the risks and uncertainties described above, the estimates and forward looking statements discussed in this annual report on Form 10 K might not occur, and our future results and our performance may differ materially from those expressed in these forward looking statements due to, including, but not limited to, the factors mentioned above. Because of these uncertainties, you should not place undue reliance on these forward looking statements.

Table of Contents

PART I
Item 1. Business
General

Kosmos is a leading independent oil and gas exploration and production company focused on frontier and emerging areas along the Atlantic Margins. Our assets include existing production and development projects offshore Ghana and Equatorial Guinea, large discoveries and significant further exploration potential offshore Mauritania and Senegal, as well as exploration licenses offshore Cote d'Ivoire, Equatorial Guinea, Morocco, Sao Tome and Principe, and Suriname. Kosmos is listed on the New York Stock Exchange (“NYSE”) and London Stock Exchange ("LSE") and is traded under the ticker symbol KOS.
Kosmos was founded in 2003 to find oil in under explored or overlooked parts of West Africa. Members of the management team—who had previously worked together making significant discoveries and developing them in Africa, the Gulf of Mexico, and other areas—established the company on a single geologic concept that previously had been disregarded by others in the industry, the Late Cretaceous play system.
Following our formation, we acquired multiple exploration licenses and proved the geologic concept with the discovery of the Jubilee Field within the Tano Basin in the deep waters offshore Ghana in 2007. This was the first of our discoveries offshore Ghana; it was one of the largest oil discoveries worldwide in 2007 and is considered one of the largest finds offshore West Africa during that decade. As technical operator of the initial phase of the Jubilee Field, we led an Integrated Project Team ("IPT") that planned and executed the development. Oil production from the Jubilee Field began in November 2010, just 42 months after initial discovery, a record for a deepwater development in this water depth in West Africa.
Kosmos and our partners discovered the Tweneboa, Enyenra and Ntomme ("TEN") fields in 2009, 2010 and 2012, respectively. The TEN fields are being developed through a phased manner delivering first oil in August 2016, and thus, becoming our second producing asset offshore Ghana. The project was delivered on time and within budget.

Following our Initial Public Offering in 2011, we acquired several new exploration licenses and again proved a new geologic concept with the Ahmeyim discovery (formerly known as Tortue) in the deepwater offshore Mauritania in 2015. The Ahmeyim discovery was one of the largest natural gas discoveries worldwide in 2015 and is believed to be the largest ever gas discovery offshore West Africa. We have since demonstrated the extension of this gas discovery into Senegal with the successful Guembeul-1 exploration well, which we collectively call the Greater Tortue discovery. We have now drilled six successful exploration and appraisal wells offshore Mauritania and Senegal, and in aggregate have discovered a gross potential natural gas resource of approximately 40 trillion cubic feet and derisked over 40 trillion cubic feet.

In November 2017, through a joint venture with an affiliate of Trident Energy ("Trident"), we acquired all of the equity interest of Hess International Petroleum Inc., a subsidiary of Hess Corporation ("Hess"), which holds an 85% paying interest (80.75% revenue interest) in the Ceiba Field and Okume Complex assets. Under the terms of the agreement with Trident, Kosmos and Trident each own 50% of Hess International Petroleum Inc. Hess International Petroleum Inc. was subsequently renamed Kosmos-Trident International Petroleum Inc. ("KTIPI"). The gross acquisition price was $650 million effective as of January 1, 2017. Kosmos paid net cash consideration of approximately $231 million at close in November 2017, after customary purchase price adjustments. The transaction is accounted for as an equity method investment. Kosmos is primarily responsible for exploration and subsurface evaluation while Trident is primarily responsible for production operations and optimization. The transaction expands our position in the Gulf of Guinea and provides immediate cash flow through existing production with potential to increase existing production and also provides step-out exploration opportunities with potential low cost tie-back through existing infrastructure.

Our business strategy focuses on achieving three key objectives: (1) maximize the value of our producing assets; (2) appraise and develop our discovered resources offshore Mauritania and Senegal; and (3) increase value further through a high impact exploration program which is designed to unlock new petroleum systems. We are focused on increasing production, cash flows and reserves from the Jubilee and TEN fields as well as our recently acquired Ceiba and Okume fields. In Mauritania and Senegal, we expect to fully appraise our Greater Tortue discovery with the objective of making a final investment decision around the end of 2018 and producing first gas in late 2021, as well as advance our other discoveries to development. We also have a large inventory of leads and prospects in our exploration portfolio which we plan to continue to mature for future drilling. We plan to test the prospectivity of high impact opportunities in the coming years along the Atlantic Margins.

Table of Contents

Our Business Strategy

Grow proved reserves and production through exploration, appraisal and development

In the near term, we plan to grow proved reserves and production by further developing our fields offshore Ghana and Equatorial Guinea. In Ghana, we plan to resume drilling at both the Jubilee Field, which now includes our Mahogany and Teak discoveries, pursuant to the Greater Jubilee Full Field Development Plan ("GJFFDP"), and at TEN through the drilling of additional development and production wells in 2018. In Equatorial Guinea, through our joint venture with Trident, we plan to maximize reserves and production through production optimization and in-fill drilling. In addition, we plan to sanction the first phase of the Greater Tortue development offshore Mauritania and Senegal which will define the path to first gas. Growth could also be realized through the development of all or a portion of our other discoveries in Mauritania and Senegal.

Focus on optimally developing our discoveries to initial production

Our development focus is designed to accelerate production, deliver early learnings and maximize returns. In certain circumstances, we believe a phased approach can be employed to optimize full field development through a better understanding of dynamic reservoir behavior and enable activities to be performed in a parallel rather than a sequential manner. A phased approach also facilitates refinement of the development plans based on experience gained in initial phases of production and by leveraging existing infrastructure as subsequent phases of development are implemented. Production and reservoir performance from the initial phases are monitored closely to determine the most efficient and effective techniques to maximize the recovery of reserves and returns. Other benefits include minimizing upfront capital costs, reducing execution risks through smaller initial infrastructure requirements, and enabling cash flow from the initial phases of production to fund a portion of capital costs for subsequent phases. In contrast, a traditional development approach consists of full appraisal, conceptual engineering, preliminary engineering, detailed engineering, procurement and fabrication of facilities, development drilling and installation of facilities for the full field development, all performed sequentially, before first production is achieved. This traditional approach can considerably lengthen the time from discovery to first production.

For example, post discovery in 2007, first oil production from the Jubilee Field commenced in November 2010. This development timeline from discovery to first oil was significantly less than the seven to ten year industry average and set a record for a deepwater development of this size and scale at this water depth in West Africa. This condensed timeline reflects the lessons learned by our experienced team while leading other large scale deepwater developments. The Greater Tortue development is also expected to be developed in an accelerated, phased approach consistent with our business strategy.

Successfully open and develop our offshore exploration plays

We believe the prospects and leads offshore Equatorial Guinea, Mauritania, Senegal, Sao Tome and Principe, Cote d'Ivoire, and Suriname provide favorable opportunities to create substantial value through exploration drilling. During 2018, we plan to test this potential in Suriname and in other areas starting in 2019. Given the potential size of these prospects and leads, we believe that exploratory success in our operating areas could significantly add to our growth profile.

Identify, access and explore frontier and emerging regions and hydrocarbon plays

Our management and exploration teams have demonstrated an ability to identify regions and hydrocarbon plays that have the potential to yield multiple large commercial discoveries. We focus on frontier and emerging areas that have been under-explored yet offer attractive commercial terms as a result of reduced competition and first mover advantage. We expect to continue to use our systematic and proven geologically focused approach in frontier and emerging petroleum systems where geological data suggests hydrocarbon accumulations are likely to exist, but where commercial discoveries have yet to be made. We believe this focus on poorly understood, under explored or otherwise overlooked hydrocarbon basins enables us to unlock significant hydrocarbon potential and create substantial value for shareholders.

This approach and focus, coupled with a first mover advantage and our management and technical teams' discipline in execution, provide a competitive advantage in identifying and accessing new strategic growth opportunities. We expect to continue seeking new opportunities where hydrocarbons have not been discovered or produced in meaningful quantities by leveraging the reputation and relationships of our experienced technical and management teams. This includes our existing areas of interest as well as selectively expanding our reach into other locations. In addition to ideas developed organically, farm in opportunities may offer a way to participate in new venture opportunities to undertake exploration in emerging basins, new plays and fairways to enhance and optimize our portfolio. Consistent

Table of Contents

with this strategy, we may also evaluate potential corporate and asset acquisition opportunities as a source of new ventures to support and expand our asset portfolio.

Kosmos Exploration Approach

Kosmos' exploration philosophy is deeply rooted in a fundamental, geologically based approach geared toward the identification of poorly understood, under explored or overlooked petroleum systems. This process begins with detailed geologic studies that methodically assess a particular region's subsurface, with careful consideration given to those attributes that suggest working petroleum systems. The process includes basin modeling to predict oil or gas charge and fluid migration, as well as stratigraphic and structural analysis to identify reservoir/seal pair development and trap definition. This analysis integrates data from previously drilled wells, where available, and seismic data. Importantly, this approach also takes into account a detailed analysis of geologic timing to ensure that we have an appropriate understanding of whether the sequencing of geological events could promote and preserve hydrocarbon accumulations. Once an area is high graded based on this play/fairway analysis, geophysical analysis based on new 3D seismic is conducted to identify prospective traps of interest.

Alongside the subsurface analysis, Kosmos performs an analysis of country specific risks to gain an understanding of the "above ground" dynamics, which may influence a particular country's relative desirability from an overall oil and natural gas operating and risk adjusted return perspective. This process is employed in both areas that have existing oil and natural gas production, as well as those regions that have yet to achieve commercial hydrocarbon production.

Once an area of interest has been identified, Kosmos targets licenses over the particular basin or fairway to achieve an early mover or in many cases a first mover advantage. In terms of license selection, Kosmos targets specific regions that have sufficient size to manage exploration risks and provide scale should the exploration concept prove successful. Kosmos also looks for long term contract duration to enable the "right" exploration program to be executed, play type diversity to provide multiple exploration concept options, prospect dependency to enhance the chance of replicating success and sufficiently attractive fiscal terms to maximize the commercial viability of discovered hydrocarbons.

Apply our entrepreneurial culture, which fosters innovation and creativity, to continue our successful exploration and development program

Our employees are critical to the success of our business strategy and we have created an environment that enables them to focus their knowledge, skills and experience on finding and developing new fields. Culturally, we have an open, team oriented work environment that fosters entrepreneurial, creative and contrarian thinking. This approach enables us to fully consider and understand both risk and reward, as well as deliberately and collectively pursue strategies that create and maximize value. This philosophy and approach was successfully utilized offshore Ghana, Mauritania and Senegal, resulting in the discovery of significant new petroleum systems, which the industry previously did not consider either prospective or commercially viable.

Build the right strategic partnerships with complementary capabilities

We look to partner with high quality industry players with world class complementary capabilities early in our exploration projects. This strategy is designed to ensure that upon successful exploration and appraisal activities, the project can benefit from specific expertise provided by these partners, including exploration, development, production and above-ground capabilities. We have proven we can execute this strategy by partnering with supermajors including BP PLC ("BP"), Chevron Corporation ("Chevron") and Total S.A. ("Total") across our exploration portfolio. In addition, bringing in the right strategic partners early in our projects often comes with a financial carry on future expenditures, allowing us to reduce our cost basis and increase return on investment.

During the second quarter of 2017, we formed the Kosmos-BP Strategic Exploration Alliance ("Alliance"). This Alliance broadens the relationship that previously covered new venture opportunities in Mauritania, Senegal and The Gambia to create an Atlantic Margin explorer-developer partnership. The Alliance leverages our regional exploration knowledge and capability together with BP's deepwater development expertise to execute a selective, joint frontier and emerging basin exploration strategy in the Atlantic Margin.

Table of Contents

Maintain Financial Discipline

We strive to maintain a conservative financial profile and strong balance sheet with ample liquidity. Typically, we fund exploration and development activities from a combination of operating cash flows, debt and partner carries. As of December 31, 2017, after consideration of the refinancing of our RBL Facility in February 2018 which increased our availability to $1.5 billion, we had approximately $1.3 billion of liquidity available to fund our opportunities. During 2017, Kosmos generated approximately $236.6 million of cash flow from operations.

Additionally, we use derivative instruments to partially limit our exposure to fluctuations in oil prices and interest rates. We have an active commodity hedging program where we aim to hedge a portion of our anticipated sales volumes on a two to three year rolling basis. As of December 31, 2017, we have hedged positions covering 19.4 million barrels of oil from 2018 through 2019 oil production, which provide partial downside protection should Dated Brent oil prices fall below our floor prices. We also maintain insurance to partially protect against loss of production revenues from our producing assets.

Operations by Geographic Area

We currently have operations in Africa and South America. Presently, all operating revenues are generated from our operations offshore Ghana. We also have an equity method investment generating revenues with operations offshore Equatorial Guinea.

Our Fields

Information about our deepwater fields is summarized in the following table.

Fields	License		Kosmos Participating Interest			Operator		Stage
Ghana								
Jubilee(1)	WCTP/DT	(2)	24.1	%	(2)	Tullow		Production
TEN(1)	DT		17.0	%	(4)	Tullow		Production
Akasa	WCTP		30.9	%	(5,6)	Kosmos	(5)	Appraisal
Wawa	DT		18.0	%	(6)	Tullow		Appraisal
Mauritania								
Ahmeyim	Block C8	(3)	28.0	%	(7)	BP		Appraisal
Marsouin	Block C8		28.0	%	(7)	BP		Appraisal
Senegal								
Guembeul	Saint Louis Offshore Profond	(3)	30.0	%	(8)	BP	(8)	Appraisal
Teranga	Cayar Offshore Profond		30.0	%	(8)	BP	(8)	Appraisal
Yakaar	Cayar Offshore Profond		30.0	%	(8)	BP	(8)	Appraisal
Equatorial Guinea								
Ceiba Field and Okume Complex - Equity Method Investment(1)	Block G		40.4	%	(9)	KTEGI	(9)	Production

(1) For information concerning our estimated proved reserves as of December 31, 2017, see "—Our Reserves."

(2) The Jubilee Field straddles the boundary between the West Cape Three Points ("WCTP") petroleum contract and the Deepwater Tano ("DT") petroleum contract offshore Ghana. To optimize resource recovery in this field, we entered into the Unitization and Unit Operating Agreement (the "UUOA") in July 2009 with the Ghana National Petroleum Corporation ("GNPC") and the other block partners of each of these two blocks. The UUOA governs the interests in and development of the Jubilee Field and created the Jubilee Unit from portions of the WCTP petroleum contract and the DT petroleum contract areas. As a result of the approval of the GJFFDP by Ghana's Ministry of Energy in October 2017, operatorship for the Mahogany and Teak discoveries transferred to Tullow which are now included

in the Jubilee Field.

Table of Contents

These interest percentages are subject to redetermination of the participating interests in the Jubilee Field pursuant to the terms of the UUOA. Our paying interest on development activities in the Jubilee Field is 26.9%.

(3) The Greater Tortue resource, which includes the Ahmeyim discovery in Mauritania Block C8 and the Guembeul discovery in the Senegal Saint Louis Offshore Profond Block, straddles the border between Mauritania and Senegal.

In February 2018, the governments of Mauritania and Senegal signed an Inter-Governmental Cooperation Agreement ("ICA") which enables the development of the cross-border Tortue natural gas field to continue moving forward.

(4) Our paying interest on development activities in the TEN fields is 19%.

(5) Our paying interest on development activities in this discovery is 26.9%. Our participating interest as of December 31, 2017 is 30.0%. The WCTP partners transferred operatorship of the remaining portions of the WCTP Block, including the Akasa discovery, to Tullow effective February 1, 2018. Kosmos continues to assist Tullow with the transition process, which is expected to extend into the first half of 2018.

(6) GNPC has the option to acquire additional paying interests in a commercial discovery on the WCTP Block and the DT Block of 2.5% and 5.0%, respectively. These interest percentages do not give effect to the exercise of such options.

(7) SMHPM has the option to acquire up to an additional 4% paying interests in a commercial development. These interest percentages do not give effect to the exercise of such option.

(8) PETROSEN has the option to acquire up to an additional 10% paying interests in a commercial development on the Saint Louis Offshore Profond and Cayar Offshore Profond blocks. The interest percentage does not give effect to the exercise of such option.

(9) Kosmos owns a 50% interest in KTIPI which holds an 85% interest in the Ceiba Field and Okume Complex through its wholly-owned subsidiary, Kosmos-Trident Equatorial Guinea Inc. ("KTEGI"), representing a 40.375% net indirect interest to Kosmos. Kosmos and Trident provide operational management and support to KTEGI, who is operator of the Ceiba Field and Okume Complex.

Table of Contents

Exploration License Areas

	Operator (Participating Interest)		Partners (Participating Interest)
Cote D'Ivoire			
Block CI-526	Kosmos (45%)	(1)	BP (45%), PETROCI (10%)
Block CI-602	Kosmos (45%)	(1)	BP (45%), PETROCI (10%)
Block CI-603	Kosmos (45%)	(1)	BP (45%), PETROCI (10%)
Block CI-707	Kosmos (45%)	(1)	BP (45%), PETROCI (10%)
Block CI-708	Kosmos (45%)	(1)	BP (45%), PETROCI (10%)
Equatorial Guinea			
Block EG-21	Kosmos (40%)	(2)	Trident (40%), GEPetrol (20%)
Block S	Kosmos (40%)	(2)	Trident (40%), GEPetrol (20%)
Block W	Kosmos (40%)	(2)	Trident (40%), GEPetrol (20%)
Mauritania			
Block C6	BP (62%)	(3)	Kosmos (28%), SMHPM (10%)
Block C8	BP (62%)	(3)	Kosmos (28%), SMHPM (10%)
Block C12	BP (62%)	(3)	Kosmos (28%), SMHPM (10%)
Block C13	BP (62%)	(3)	Kosmos (28%), SMHPM (10%)
Block C18	Total (45%)	(3)	Kosmos (15%), BP (15%), Tullow (15%), SMHPM (10%)
Morocco			
Essaouira	Kosmos (75%)		ONHYM (25%)
Sao Tome and Principe (4)			
Block 5	Kosmos (45%)		Galp (20%), Equator (20%), ANP (15%),
Block 6	Galp (45%)		Kosmos (45%), ANP (10%)
Block 11	Kosmos (65%)		Galp (20%), ANP (15%)
Block 12	Kosmos (45%)		Galp (20%), Equator (22.5%), ANP (12.5%),
Senegal			
Cayar Offshore Profond	BP (60%)	(5)	Kosmos (30%), PETROSEN (10%)
Saint Louis Offshore Profond	BP (60%)	(5)	Kosmos (30%), PETROSEN (10%)
Suriname			
Block 42	Kosmos (33%)		Chevron (33%), Hess (33%)
Block 45	Kosmos (50%)		Chevron (50%)

(1) PETROCI has the option to acquire up to an additional 2% paying interests in a commercial development. The interest percentage does not give effect to the exercise of such option.

(2) These agreements are fully executed, but are pending Presidential ratification. We presently have an 80% interest and are the operator in all three blocks, but pursuant to an agreement with Trident we expect to assign a 40% interest in the blocks to an affiliate of Trident after presidential ratification. The interest percentage gives effect to the 40% interest assignment to Trident. Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest for all development and production operations.

(3) BP is the operator of record while Kosmos provides technical exploration operator services. Should a commercial discovery be made, SMHPM’s 10% carried interest is extinguished and SMHPM will have an option to acquire a participating interest in the discovery area between 10% and 14% (blocks C8, C12 and C13), 10% and 15% (Block C18) and 10% and 18% (Block C6). SMHPM will pay its portion of development and production costs in a commercial development on the blocks. The interest percentage does not give effect to the exercise of such option.

(4) Kosmos and BP have been awarded the rights to negotiate petroleum contracts for blocks 10 and 13.

Table of Contents

(5) PETROSEN has the option to acquire up to an additional 10% paying interest in a commercial development on the Saint Louis Offshore Profond and Cayar Offshore Profond blocks. The interest percentage does not give effect to the exercise of such option.

Table of Contents

Ghana

The WCTP Block and DT Block are located within the Tano Basin, offshore Ghana. This basin contains a proven world class petroleum system as evidenced by our discoveries. The following is a brief discussion of our discoveries on our license areas offshore Ghana.

Jubilee Field

The Jubilee Field was discovered by Kosmos in 2007, with first oil produced in November 2010. Appraisal activities confirmed that the Jubilee discovery straddled the WCTP and DT Blocks. Pursuant to the terms of the UUOA, the discovery area was unitized for purposes of joint development by the WCTP and DT Block partners.

The Jubilee Field is a combination structural stratigraphic trap with reservoir intervals consisting of a series of stacked Upper Cretaceous Turonian aged, deepwater turbidite fan lobe and channel deposits.

The Jubilee Field is located approximately 37 miles offshore Ghana in water depths of approximately 3,250 to 5,800 feet, which led to the decision to implement an FPSO based development. The FPSO is designed to provide water and natural gas injection to support reservoir pressure, to process and store oil and to export gas through a pipeline to the mainland. The Jubilee Field is being developed in a phased approach. The Phase 1 development focused on partial development of certain reservoirs in the Jubilee Field. The Kosmos led Integrated Project Team (“IPT”) successfully executed the initial 17 well development plan, which included nine producing wells that produced through subsea infrastructure to the “Kwame Nkrumah” FPSO, six water injection wells and two natural gas injection wells. This initial phase provided subsea infrastructure capacity for additional production and injection wells to be drilled in future phases of development.

The Phase 1A development plan provided further development to the currently producing Jubilee Field reservoirs. The Phase 1A development included the drilling of eight additional wells consisting of five production wells and three water injection wells. Approval was given for an additional well, a gas injector, considered as part of Phase 1A. The Phase 1A Addendum PoD was submitted to the Ministry of Energy in June 2015 and deemed approved in July 2015 to enable drilling and completion of two additional wells consisting of one production well and one water injection well.

The Greater Jubilee Full Field Development Plan (“GJFFDP”) was resubmitted to the government of Ghana in September 2017 and subsequently approved in October 2017. This plan, which is expected to increase proved reserves and extend the field production profile, has been optimized to reduce overall capital expenditures to reflect the current oil price market. In November 2015, we signed the Jubilee Field Unit Expansion Agreement with our partners, which became effective upon approval of the GJFFDP, to allow for the development of the Mahogany and Teak discoveries through the Jubilee FPSO and infrastructure, thus reducing their development cost. As a result of the approval of the GJFFDP by the Ministry of Energy in October 2017, operatorship for the Mahogany and Teak discoveries transferred to Tullow. The WCTP partners transferred operatorship of the remaining portions of the WCTP Block, including the Akasa discovery, to Tullow effective February 1, 2018. Kosmos continues to assist Tullow with the transition process, which is expected to extend into the first half of 2018.

The Government of Ghana completed the construction and connection of a gas pipeline from the Jubilee Field to transport natural gas to the mainland for processing and sale. In November 2014, the transportation of gas produced from the Jubilee Field commenced through the gas pipeline to the onshore gas plant. However, the uptime of the facility in future periods is not known. In the absence of the continuous export of large quantities of natural gas from the Jubilee Field, it is anticipated that we will need to reinject or flare such natural gas. Our inability to continuously export associated natural gas in large quantities from the Jubilee Field could impact our oil production.

In prior years, certain near wellbore productivity issues were identified, impacting several Phase 1 production wells. The Jubilee Unit partners identified a means of successfully mitigating the near wellbore productivity issues with ongoing acid stimulation treatments. We have also experienced mechanical issues in the Jubilee Field, including failures of our water injection and gas compression facilities on the FPSO. This equipment downtime negatively impacted past oil production. We are in the process of correcting mechanical issues experienced in the Jubilee Field.

In February 2016, the Jubilee Field operator identified an issue with the turret bearing of the FPSO Kwame Nkrumah. This necessitated the FPSO to be shut down for an extended period beginning in March 2016 with production resuming in early May 2016. This resulted in the need to implement new operating and offloading procedures, including the use of tug boats for heading control and a dynamically positioned (“DP”) shuttle tanker and storage vessel for offloading.

Table of Contents

Kosmos and its partners have determined the preferred long-term solution to the turret bearing issue is to convert the FPSO to a permanently spread moored facility. The Jubilee turret remediation work is progressing as planned and the FPSO spread-mooring at its current heading was completed in February 2017. This allowed the tug boats previously required to hold the vessel on a fixed heading to be removed, significantly reducing the cost and complexity of the current operation. The next phase of the remediation work involves lifting and locking the main turret bearing. With regard to the turret remediation plan, the partnership is aligned on the engineering solution. This involves a shutdown to stabilize the turret bearing during the first quarter of 2018 followed by work to rotate the vessel to a new heading and permanently spread moor the vessel. The turret stabilization shutdown is being conducted in two phases, the first of which is complete and oil production is back online. The second phase is expected to commence around the end of the first quarter of 2018, and we anticipate the overall shutdown of oil production for both phases to be around four weeks. It is anticipated the gas system will be shut-in for slightly longer to complete non-turret related maintenance. We now expect the rotation of the vessel to take place around the end of 2018 with minimal impact to production in 2018.

The financial impact of lower Jubilee production as well as the additional expenditures associated with the damage to the turret bearing is mitigated through a combination of the comprehensive Hull and Machinery insurance (“H&M”), procured by the operator, Tullow, on behalf of the Jubilee Unit partners, and the corporate Loss of Production Income (“LOPI”) insurance procured by Kosmos. Our LOPI coverage for this incident ended in May 2017 and the final cash proceeds were received in August 2017. Oil production from the Jubilee Field averaged approximately 93,500 barrels (gross) of oil per day during 2017.

Tweneboa, Enyenra and Ntomme ("TEN")

The TEN fields are located in the western and central portions of the DT Block, approximately 30 miles offshore Ghana in water depths of approximately 3,300 to 5,700 feet. In November 2012, we submitted a declaration of commerciality and PoD over the TEN discoveries. In May 2013, the government of Ghana approved the TEN PoD. The discoveries are being jointly developed with shared infrastructure and a single FPSO.

The TEN fields consist of multiple stratigraphic traps with reservoir intervals consisting of a series of stacked Upper Cretaceous Turonian aged, deepwater fan lobes and channel deposits.

The TEN fields are being developed in a phased manner. The TEN PoD was designed to include an expandable subsea system that would provide for multiple phases. Phase 1 of the TEN PoD includes the drilling and completion of up to 17 wells, 11 of which have been completed. Seven additional development wells are expected to be drilled during Phase 2. The remaining Phase 1 and Phase 2 wells are a combination of production wells and water or gas injection wells needed to maximize recovery.

Following first oil from the TEN fields in August 2016, oil production and water injection systems were commissioned and are now operational. In January 2017, the capacity of the FPSO was successfully tested at an average rate of 80,000 Bopd during a short-term flow test. However, due to certain issues with managing pressures in the Enyenra reservoir and because no new wells could be drilled until after the previously disclosed Special Chamber of the International Tribunal of the Sea (ITLOS) ruling , the operator has elected to manage the existing wells in a prudent manner to optimize long-term recovery over the lifetime of the field. This reservoir management is not expected to negatively impact the ultimate field recovery. In September 2017, ITLOS issued its final decision in the maritime boundary dispute between the Governments of Ghana and Cote d'Ivoire. The maritime boundary delimited by the Special Chamber's decision had no impact on TEN production or reserves or otherwise on our interests in Ghana. Production from TEN in the year ended December 31, 2017 averaged approximately 55,800 bopd. We expect to resume drilling in early 2018 and production is expected to increase towards FPSO capacity.

The construction and connection of a gas pipeline between the Jubilee and TEN fields to transport natural gas to the mainland for processing and sale was completed in the first quarter of 2017. In December 2017, we signed the TEN Associated-Gas Gas Sales Agreement (TAG GSA) and we expect to begin exporting TEN associated gas to shore in the second quarter of 2018. The TAG GSA provides for a sales price of $0.50 price per mmbtu. However, the uptime of the gas processing facility in future periods is not known. Our inability to continuously export associated natural gas in large quantities from the TEN fields could impact our oil production.

Other Ghana Discoveries

The Akasa discovery is located in the western portion of the WCTP Block approximately 31 miles offshore Ghana in water depths of approximately 3,200 to 5,050 feet. The discovery is southeast of the Jubilee Field. We believe the target reservoirs are channels and lobes that are stratigraphically trapped. The Akasa 1 well intersected oil bearing reservoirs in the Turonian zones. Fluid samples recovered from the well indicate an oil gravity of 38 degrees API.

Table of Contents

The Wawa discovery is located within the DT Block, north of the TEN fields. The Wawa 1 exploration well intersected oil and gas condensate in a Turonian aged turbidite channel system. In April 2016, the Ghana Ministry of Energy approved our request to enlarge the TEN development and production area subject to continued subsurface and development concept evaluation, along with the requirement to integrate the Wawa Discovery into the TEN PoD.

Mauritania

The C6, C8, C12, C13 and C18 blocks are located on the western margin of the Mauritania Salt Basin offshore Mauritania. These blocks are located in a proven petroleum system, with our primary targets being Cretaceous sands in structural and stratigraphic traps. We believe that the Triassic salt basin formed at the onset of rifting and contains Jurassic, Cretaceous and Tertiary passive margin sequences of limestones, sandstone and shales. Interpretation of available geologic and geophysical data has identified Cretaceous slope channels and basin floor fans in trapping geometries outboard of the Salt Basin as the key exploration objective. Multiple Cretaceous source rocks penetrated by wells and typed to oils and gases in the Mauritania Salt Basin are the same age as those which charge other oil and gas fields in West Africa.

A portion of this acreage is located outboard of the Chinguetti Field and ranges in water depth from 330 to 9,800 feet. These blocks cover an aggregate area of approximately 6.0 million acres. We have acquired approximately 6,300 line-kilometers of 2D seismic data and 15,800 square kilometers of 3D seismic data covering portions of our blocks in Mauritania. Based on these 2D and 3D seismic programs, we have drilled two successful exploration wells and an appraisal well, and have identified numerous additional prospects in our blocks. We continue to integrate the results of our drilling program in Mauritania to identify and mature primary targets in preparation for drilling.

Senegal

The Senegal Blocks are located in the Senegal River Cretaceous petroleum system and range in water depth from 980 to 10,200 feet. The area is an extension of the working petroleum system in the Mauritania Salt Basin. We believe the area has multiple Cretaceous source rocks with Albian through Cenomanian reservoir sands providing exploration targets. We acquired approximately 7,000 square kilometers of 3D seismic data over the central and eastern portions of the Senegal Blocks in January 2015. In February 2016, we completed a 4,500 square kilometer survey over the western portions of the Senegal Blocks to fully evaluate the prospectivity. We have drilled two successful exploration wells and an appraisal well, and have identified numerous prospects in our blocks and we continue to mature these for drilling.

The following is a brief discussion of our discoveries to date offshore Mauritania and Senegal.

Greater Tortue Discovery

The Ahmeyim and Guembeul discoveries (collectively “Greater Tortue”) are significant, play-opening gas discoveries for the outboard Cretaceous petroleum system and are located approximately 75 miles offshore Mauritania and Senegal. The Greater Tortue discovery straddles Block C8 offshore Mauritania and Saint Louis Offshore Profond offshore Senegal.

We have now drilled three wells within the Greater Tortue discovery. The wells penetrated multiple excellent quality gas reservoirs, including the Lower Cenomanian, Upper Cenomanian and underlying Albian. The wells successfully delineated the Ahmeyim and Guembeul gas discoveries and demonstrated reservoir continuity, as well as static pressure communication between the three wells drilled within the Lower Cenomanian reservoir. The discovery ranges in water depths from 8,850 feet to 9,200 feet, with total depths drilled ranging from 16,700 feet to 17,200 feet.

The Tortue-1 discovery well, located in Block C8 offshore Mauritania, intersected approximately 117 meters (383 feet) of net hydrocarbon pay. A single gas pool was encountered in the Lower Cenomanian objective, which is comprised of three reservoirs totaling 88 meters (288 feet) in thickness over a gross hydrocarbon interval of 160 meters (528 feet). A fourth reservoir totaling 19 meters (62 feet) was penetrated within the Upper Cenomanian target over a gross hydrocarbon interval of 150 meters (492 feet). The exploration well also intersected an additional 10 meters (32 feet) of net hydrocarbon pay in the lower Albian section, which is interpreted to be gas.

The Guembeul-1 discovery well, located in the northern part of the Saint Louis Offshore Profond area in Senegal, is located approximately three miles south of the Tortue-1 exploration well in Mauritania. The well encountered 101 meters (331 feet) of net gas pay in two excellent quality reservoirs, including 56 meters (184 feet) in the Lower

Cenomanian and 45 meters (148 feet) in the underlying Albian, with no water encountered.
The Ahmeyim-2 appraisal well is located in Block C8 offshore Mauritania, approximately three miles northwest, and 200 meters down-dip of the basin-opening Tortue-1 discovery. The well confirmed significant thickening of the gross reservoir

Table of Contents

sequences down-dip. The Ahmeyim-2 well encountered 78 meters (256 feet) of net gas pay in two excellent quality reservoirs, including 46 meters (151 feet) in the Lower Cenomanian and 32 meters (105 feet) in the underlying Albian.

In August 2017, we announced the successful completion of the drill stem test ("DST") of the Tortue-1 well, demonstrating that the Tortue field is a world-class resource and confirming key development parameters including well deliverability, reservoir connectivity, and fluid composition. The Tortue-1 well flowed at a sustained, equipment-constrained rate of approximately 60 million cubic feet per day (MMcfd) during the main extended flow period, with minimal pressure drawdown, providing confidence in well designs that are each capable of producing approximately 200 MMcfd. The DST results confirmed a connected volume per well consistent with the current development scheme, which together with the high well rate is expected to result in a low number of development wells compared to equivalent schemes. Initial analysis of fluid samples collected during the test indicate Tortue gas is well suited for liquefaction given low levels of liquids and minimal impurities. Data acquired from the DST will be used to further optimize field development and to refine process design parameters critical to the front end engineering and design ("FEED") process.

Other Mauritania and Senegal Discoveries

The BirAllah discovery (formally known as Marsouin), located in Block C8 offshore Mauritania, is a significant, play-extending gas discovery, building on our successful exploration program in the outboard Cretaceous petroleum system offshore Mauritania. The Marsouin-1 well is located approximately 37 miles north of the Ahmeyim discovery and was drilled to a total depth of 16,900 feet in nearly 7,900 feet of water. Based on analysis of drilling results and logging data, Marsouin-1 encountered at least 70 meters (230 feet) of net gas pay in Upper and Lower Cenomanian intervals comprised of excellent quality reservoir sands.

The Teranga discovery is located in the Cayar Offshore Profond block approximately 40 miles northwest of Dakar, and was our second exploration well offshore Senegal. The Teranga-1 discovery well is located in nearly 5,900 feet of water and was drilled to a total depth of 15,900 feet. The well encountered 31 meters (102 feet) of net gas pay in good quality reservoir in the Lower Cenomanian objective. Well results confirm that a prolific inboard gas fairway extends approximately 125 miles south from the Marsouin-1 well in Mauritania through the Greater Tortue area on the maritime boundary to the Teranga-1 well in Senegal.

The Yakaar discovery is located in the Cayar Offshore Profond block offshore Senegal, approximately 60 miles northwest of Dakar in approximately 2,600 meters of water. The Yakaar-1 discovery well was drilled to a total depth of approximately 4,900 meters. The well intersected a gross hydrocarbon column of 120 meters (394 feet) in three pools within the primary Lower Cenomanian objective and encountered 45 meters (148 feet) of net pay.

These discoveries collectively have discovered a gross potential natural gas resource of approximately 40 trillion cubic feet and as such derisked over 40 trillion cubic feet in the basin.

Equatorial Guinea

In October 2017, we entered into petroleum contracts covering Blocks EG-21, S, and W with the Republic of Equatorial Guinea. Ratification of the petroleum contracts by the President of Equatorial Guinea is required before the contracts become effective. The petroleum contracts cover approximately 6,000 square kilometers, with a first exploration period of five years from the date of notification of ratification by the President of Equatorial Guinea. The first exploration period consists of two sub-periods of three and two years, respectively. The first exploration sub-period work program includes an approximately 6,000 square kilometer 3D seismic acquisition requirement across the blocks.

Table of Contents

Ceiba Field and Okume Complex - Equity Method Investment

In the fourth quarter of 2017, through a joint venture with an affiliate of Trident, we acquired all of the equity interest of Hess International Petroleum Inc., a subsidiary of Hess, which holds an 85% paying interest (80.75% revenue interest) in the Ceiba Field and Okume Complex assets. Under the terms of the agreement, Kosmos and Trident each own 50% of Hess International Petroleum Inc. Hess International Petroleum Inc. was subsequently renamed Kosmos-Trident International Petroleum Inc. ("KTIPI"). Kosmos is primarily responsible for exploration and subsurface evaluation while Trident is primarily responsible for production operations and optimization. The transaction expands our position in the Gulf of Guinea and provides immediate cash flow through existing production with potential to increase existing production and also provides step-out exploration opportunities with potential low cost tie-back through existing infrastructure. The gross acquisition price is $650 million effective as of January 1, 2017. After post closing entries Kosmos paid net cash of approximately $231 million, with a combination of cash on hand and availability under the Facility. The transaction is accounted for as an equity method investment. Oil production from the Ceiba Field and Okume Complex averaged approximately 45,000 barrels (gross) of oil per day during the period we held an interest in 2017.

Suriname

We are the operator for petroleum contracts covering Block 42 and Block 45 offshore Suriname, which are located within the Guyana Suriname Basin, along the Atlantic transform margin of northern South America. Suriname lies between Guyana to the west and French Guyana to the east. The Guyana-Suriname Basin was formed by tensional forces associated with the opening of the Atlantic Ocean as South America separated from Africa in the Mid Cretaceous period. The Suriname basin is considered similar to the working petroleum systems of the West African transform margin. The emerging petroleum system in Suriname has been proven by the presence of onshore producing fields and most recently by nearby discoveries offshore Guyana, including the Liza-1 well.

Suriname Block 42 and Block 45 are positioned centrally in the Suriname-Guyana Basin, and located to the east of the recent play opening Liza-1 oil discovery. Likewise, the blocks are also positioned to the northwest of the French Guyana Basins' Zaedyus oil discovery.

We believe that there are several independent play types of importance on our operated blocks. Of note are the listric faulted structural stratigraphic play of the lower Cretaceous and the stratigraphically trapped Upper Cretaceous plays similar to those discovered in the Jubilee Field offshore West Africa. The recent oil discovery in Guyana (Liza-1) in the same geologic basin provides a positive point of calibration for the Upper Cretaceous stratigraphic play in Suriname.

Target reservoirs in our blocks are similar Upper and Middle Cretaceous age basin floor fans and mid slope channel sands. Seismic evidence suggests thick Late Cretaceous and Tertiary reservoir systems may be present in the deep water area demonstrated by Liza-1.

The Tambaredjo and Calcutta Fields onshore Suriname, as well as the Liza-1 well discovery offshore Guyana, demonstrate that a working petroleum system exists, and geological and geochemical studies suggest the hydrocarbons in these fields were generated from source rocks located in the offshore basin. The source rocks are believed to be analogous in age to those which have charged numerous fields in offshore West Africa.

During 2012, we completed a 3D seismic data acquisition program which covered approximately 3,900 square kilometers over portions of Block 42 and Block 45 offshore Suriname. In August 2013, we completed a 2D seismic program of approximately 1,400 line kilometers over a portion of Block 42, outside of the existing 3D seismic survey. The processing of the seismic data was completed during 2014. In December 2015, we received an extension of Phase 1 of the Exploration Period for Block 42 offshore Suriname which now expires in September 2018. In April 2016, we received an extension of Phase 1 of the Exploration Period for Block 45 offshore Suriname which now expires in September 2018.

In January 2017, we completed a 3D seismic survey of approximately 6,500 square kilometers over Block 42 and Block 45 offshore Suriname. Processing of this data is currently ongoing. We have compiled an initial inventory of prospects on the license areas in Suriname and will continue to refine and assess the prospectivity, integrating this new 3D seismic data, with plans to drill in 2018.

19

Table of Contents

Sao Tome and Principe

During 2015 and 2016, Kosmos acquired acreage in Blocks 5, 6, 11 and 12 offshore Sao Tome and Principe in the Gulf of Guinea. We are the operator of Blocks 5, 11 and 12, and Galp, a wholly owned subsidiary of Petrogal, S.A., is the operator of Block 6. These blocks cover an area of approximately 5.8 million acres in water depth ranging from 7,380 to 9,840 feet and provide an opportunity to pursue the same core Cretaceous theme that was successful for us in Ghana.

Our blocks are adjacent to, and represent an extension of a proven and prolific petroleum system offshore Equatorial Guinea and northern Gabon comprising Early Cretaceous post-rift source rocks and Late Cretaceous reservoirs.

We believe that the southern extent of the West African transform margin in Sao Tome and Principe comprises a series of Albian pull-apart basins formed during the separation of Africa from South America, providing the necessary conditions for the generation, migration and entrapment of hydrocarbons. Early in the basin history, restricted marine conditions prevailed allowing rich source rocks to be deposited. Large sandstone depo-centers were developed at the structural junctions of rift and shear fault trends resulting in the deposition of deep-water slope channels and basin floor fans draping over and around anticlinal highs adjacent to fracture zones. These constitute the main play in the acreage.

In December 2016, we received approval for a two-year extension of Phase 1 for Block 5 offshore Sao Tome and Principe, which now expires in May 2019. Additionally, during the same month we assigned 20% participating interest to Galp in each of Blocks 5, 11 and 12 offshore Sao Tome and Principe. Based on the terms of the agreement, Galp has paid a proportionate share of Kosmos’ past costs in the form of a partial carry on the 3D seismic survey.

In August 2017, we completed a 3D seismic survey of approximately 15,800 square kilometers over Blocks 5, 6, 11, and 12 offshore Sao Tome and Principe. Processing of this data is currently underway. We are compiling an initial inventory of prospects on the license areas in Sao Tome and Principe and will continue to refine and assess the prospectivity, integrating this new 3D seismic data into our geological evaluation during 2018 with a view to drilling as early as 2019.

In November 2017, we received approval for a one-year extension of Phase 1 for Block 11 offshore Sao Tome and Principe, which now expires in July 2019.

Morocco and Western Sahara

Our petroleum contracts in Morocco and Western Sahara include the Boujdour Maritime block, which is within the Aaiun Basin, and the Essaouira Offshore Block, which is within the Agadir Basin. We are the operator of these petroleum contracts.

Aaiun Basin

In November 2017, we provided to our co-venturers a notice of withdrawal from the the Boujdour Maritime block offshore Western Sahara and transferred our participating interest and operatorship to ONHYM. We are providing certain transition services to ONHYM as part of the handover of operatorship. In order to complete our obligations under the petroleum contract, we will continue to fund the remainder of the current seismic program.

Agadir Basin

The Essaouira Offshore block is located in the Agadir Basin. A working petroleum system has been established in the onshore area of the Agadir Basin based on onshore and shallow offshore wells. Existing well data and geological and geochemical studies have demonstrated the presence of Cretaceous source rocks in the acreage. Onshore production suggests that possible Jurassic source rocks are also present in the offshore Agadir Basin.

In June 2017, we completed a 3D seismic survey of approximately 3,000 square kilometers over the Essaouira Offshore Block. Additional geological studies are expected to be conducted beginning in the first quarter of 2018. The current phase of the Essaouira Offshore petroleum contract expires in November 2018.

Cote d'Ivoire

In December 2017, as part of our Alliance with BP, we entered into petroleum contracts as operator for five Offshore Blocks, CI-526, CI-602, CI-603, CI-707 and CI-708, which are located in a cenomanian-turonian petroleum system and range in water depth from 1,500 to 15,000 feet. The area is located approximately 150 kilometers west of our

TEN discoveries in Ghana. We believe the area has multiple Cretaceous source rocks with Cenomanian through Maastrichtian reservoir sands providing

Table of Contents

exploration targets. We plan to acquire approximately 12,000 square kilometers of 3D seismic data over the blocks during 2018 to evaluate the prospectivity.

Portugal

In January 2017, we provided to our co-venturers a notice of withdrawal from the Ameijoa, Camarao, Mexilhao and Ostra Blocks offshore Portugal.

BP Alliance

During the second quarter of 2017, we formed the Alliance. This Alliance broadens the relationship that previously covered new venture opportunities in Mauritania, Senegal and The Gambia to create an Atlantic Margin explorer-developer partnership. The Alliance leverages our regional exploration knowledge and capability together with BP's deepwater development expertise to execute a selective, joint frontier and emerging basin exploration strategy in the Atlantic Margin.

Our Reserves

The following table sets forth summary information about our estimated proved reserves as of December 31, 2017. See "Item 8. Financial Statements and Supplementary Data—Supplemental Oil and Gas Data (Unaudited)" for additional information.

Our estimated proved reserves as of December 31, 2017, were associated with our Jubilee and the TEN fields in Ghana as well as our share of our equity method investment in the Ceiba Field and Okume Complex in Equatorial Guinea. Our estimated proved reserves as of December 31, 2016 and 2015 were associated with our Jubilee and TEN fields in Ghana.

Summary of Oil and Gas Reserves

	2017 Net Proved Reserves(1)			2016 Net Proved Reserves(1)			2015 Net Proved Reserves(1)		
	Oil, Condensate, NGLs (MMBbl)	Natural Gas(2) (Bcf)	Total (MMBoe)	Oil, Condensate, NGLs (MMBbl)	Natural Gas(2) (Bcf)	Total (MMBoe)	Oil, Condensate, NGLs (MMBbl)	Natural Gas(2) (Bcf)	Total (MMBoe)
Reserves Category									
Proved developed	59	38	65	64	13	66	50	10	52
Proved undeveloped(3)	23	11	24	10	2	11	24	4	25
Total Kosmos	82	49	89	74	15	77	74	14	77
Equity method investment(4)	19	13	21						
Total reserves	100	61	110						

(1) Our reserves associated with the Jubilee Field are based on the 54.4%/45.6% redetermination split, between the WCTP Block and DT Block. Totals within the table may not add as a result of rounding.

(2) These reserves represent the estimated quantities of fuel gas required to operate the Jubilee and TEN FPSOs during normal field operations and the associated gas forecasted to be exported from TEN. This volume of associated gas is included as of December 31, 2017 as a result of the finalization of the TEN Associated-Gas Gas Sales Agreement (TAG GSA). If and when a subsequent gas sales agreement is executed for Jubilee, a portion of the remaining Jubilee gas may be recognized as reserves. If and when a gas sales agreement and the related infrastructure are in place for the TEN fields non-associated gas, a portion of the remaining gas may be recognized as reserves.

(3) All of our proved undeveloped reserves are expected to be developed within six years or less. Proved undeveloped reserves expected to be developed beyond five years are related to long-term projects which will be completed under a continuous drilling program. As of December 31, 2017, we recognized 24.4 MMBoe of proved

undeveloped reserves related to the Jubilee and TEN fields, representing approved future drilling in both fields.
(4) We disclose our share of reserves that are accounted for by the equity method.

Table of Contents

Changes for the year ended December 31, 2017, include an increase of 15.6 MMBbl in Jubilee related to the approval of the Greater Jubilee Full Field Development Plan (GJFFDP), partially offset by 7.7 MMBbl of net Jubilee production during 2017. Changes at TEN include an increase of 7.2 MMBoe as a result of positive Ntomme performance and the finalization of the TAG GSA, which was partially offset by 3.3 MMBbl of net TEN production during 2017. As a result of the approval of the GJFFDP, we now have 10.4 MMBbl of proved undeveloped reserves in the Greater Jubilee area, representing future infill drilling plans. Changes for 2017 also include the initial certification of proved volumes in Equatorial Guinea, representing the reserves associated with our equity method investment.
Changes for the year ended December 31, 2016, include an increase of 8.3 MMBbl in TEN related to a revision resulting from additional technical data and analysis, partially offset by 0.9 MMBbl of net TEN production during 2016, and negative revisions to Jubilee of 1.0 MMBbl due to lower oil prices and 6.2 MMBbl of net Jubilee production during 2016. During the year ended December 31, 2016, we had 14 MMBoe of our proved undeveloped reserves from December 31, 2015 convert to proved developed reserves due to the completion of seven wells in the TEN fields, the initiation of TEN production and 2016 revisions, and we incurred $198.5 million of capital expenditures for TEN.
Changes for the year ended December 31, 2015, include an increase of 11.8 MMBbl of net proved reserves related to Jubilee field performance and in fill drilling results, which were partially offset by negative revisions to the TEN fields of 2.1 MMBbl due to lower oil prices and by 8.6 MMBbl of net Jubilee production during 2015. During the year ended December 31, 2015, we had a 6 MMBoe reduction in our proved undeveloped reserves from December 31, 2014. The decrease was a result of an approximately 2 MMBoe negative revision associated with our TEN fields, due to shorter economic life as a result of lower oil price. We incurred $80.6 million of capital expenditures related the drilling and completion of two wells pursuant to the Jubilee Field Phase 1A and 1A addendum developments resulting in the conversion of approximately 3 MMBoe of proved undeveloped reserves to proved developed reserves associated with our Jubilee Field.

Table of Contents

The following table sets forth the estimated future net revenues, excluding derivatives contracts, from net proved reserves and the expected benchmark prices used in projecting net revenues at December 31, 2017. All estimated future net revenues are attributable to projected production from the Jubilee and the TEN fields in Ghana and our equity method investment. If we are unable to export associated natural gas in large quantities from the Jubilee and TEN fields then production could be limited and the future net revenues discussed herein will be adversely affected.

	Estimated Future Net Revenues(4) (in millions except $/Bbl)		
	Kosmos	Equity Method Investment	Total
Estimated future net revenues	$1,286	$ 9	$1,295
Present value of estimated future net revenues:			
PV-10(1)	$971	$ 130	$1,101
Future income tax expense (levied at a corporate parent and intermediate subsidiary level)	—	—	—
Discount of future income tax expense (levied at a corporate parent and intermediate subsidiary level) at 10% per annum	—	—	—
Standardized Measure(2)	$971	$ 130	$1,101
Benchmark and differential oil price($/Bbl)(3)	$54.42	$ 54.42	

(1) PV 10 represents the present value of estimated future revenues to be generated from the production of proved oil and natural gas reserves, net of future development and production costs, royalties, additional oil entitlements and future tax expense levied at an asset level, using prices based on an average of the first day of the months throughout 2017 and costs as of the date of estimation without future escalation, without giving effect to hedging activities, non property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10% to reflect the timing of future cash flows. PV 10 is a non GAAP financial measure and often differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of future income tax expense related to proved oil and gas reserves levied at a corporate parent level on future net revenues. However, it does include the effects of future tax expense levied at an asset level. Neither PV 10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas assets. PV 10 should not be considered as an alternative to the Standardized Measure as computed under GAAP; however, we and others in the industry use PV 10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific corporate tax characteristics of such entities.

(2) Standardized Measure represents the present value of estimated future cash inflows to be generated from the production of proved oil and natural gas reserves, net of future development and production costs, future income tax expense related to our proved oil and gas reserves levied at a corporate parent and intermediate subsidiary level, royalties, additional oil entitlements and future tax expense levied at an asset level, without giving effect to hedging activities, non property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10% to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV 10. Standardized Measure often differs from PV 10 because Standardized Measure includes the effects of future income tax expense related to our proved oil and gas reserves levied at a corporate parent level on future net revenues. However, as we are a tax exempted company incorporated pursuant to the laws of Bermuda, we do not expect to be subject to future income tax expense related to our proved oil and gas reserves levied at a corporate parent level on future net revenues. Therefore, the year end 2017 estimate of PV 10 is equivalent to the Standardized Measure.

(3)

The unweighted arithmetic average first day of the month prices for the prior 12 months was $54.42 for Dated Brent at December 31, 2017. The price was adjusted for crude handling, transportation fees, quality, and a regional price differential. These adjustments are estimated to include a $0.10 premium, a $0.02 premium and a $0.53 discount relative to Dated Brent for the Jubilee Field, TEN fields and our equity method investment, respectively. The adjusted price utilized to derive the Jubilee Field PV 10, TEN PV-10 and equity method investment PV-10 is $54.52, $54.44 and $53.89, respectively.

Table of Contents

(4) Future net revenues and PV-10 have been adjusted from the reserve report which is based on the entitlements method as we account for oil and gas revenues under the sales method of accounting.

Estimated proved reserves

Unless otherwise specifically identified in this report, the summary data with respect to our estimated net proved reserves for the years ended December 31, 2017, 2016 and 2015 has been prepared by Ryder Scott Company, L.P. ("RSC"), our independent reserve engineering firm for such years, in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") applicable to companies involved in oil and natural gas producing activities. These rules require SEC reporting companies to prepare their reserve estimates using reserve definitions and pricing based on 12 month historical unweighted first day of the month average prices, rather than year end prices. For a definition of proved reserves under the SEC rules, see the "Glossary and Selected Abbreviations." For more information regarding our independent reserve engineers, please see "—Independent petroleum engineers" below.

Our estimated proved reserves and related future net revenues, PV 10 and Standardized Measure were determined using index prices for oil, without giving effect to derivative transactions, and were held constant throughout the life of the assets.

Future net revenues represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Such calculations at December 31, 2017 are based on costs in effect at December 31, 2017 and the 12 month unweighted arithmetic average of the first day of the month price for the year ended December 31, 2017, adjusted for anticipated market premium, without giving effect to derivative transactions, and are held constant throughout the life of the assets. There can be no assurance that the proved reserves will be produced within the periods indicated or prices and costs will remain constant.

Independent petroleum engineers

Ryder Scott Company, L.P.

RSC, our independent reserve engineers for the years ended December 31, 2017, 2016 and 2015, was established in 1937. For over 75 years, RSC has provided services to the worldwide petroleum industry that include the issuance of reserves reports and audits, appraisal of oil and gas properties including fair market value determination, reservoir simulation studies, enhanced recovery services, expert witness testimony, and management advisory services. RSC professionals subscribe to a code of professional conduct and RSC is a Registered Engineering Firm in the State of Texas.

For the years ended December 31, 2017, 2016 and 2015, we engaged RSC to prepare independent estimates of the extent and value of the proved reserves of certain of our oil and gas properties. These reports were prepared at our request to estimate our reserves and related future net revenues and PV 10 for the periods indicated therein. Our estimated reserves at December 31, 2017, 2016 and 2015 and related future net revenues and PV 10 at December 31, 2017, 2016 and 2015 are taken from reports prepared by RSC, in accordance with petroleum engineering and evaluation principles which RSC believes are commonly used in the industry and definitions and current regulations established by the SEC. The December 31, 2017 reserve report was completed on January 13, 2018, and a copy is included as an exhibit to this report.

In connection with the preparation of the December 31, 2017, 2016 and 2015 reserves report, RSC prepared its own estimates of our proved reserves. In the process of the reserves evaluation, RSC did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices or any agreements relating to current and future operations of the fields and sales of production. However, if in the course of the examination something came to the attention of RSC which brought into question the validity or sufficiency of any such information or data, RSC did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data. RSC independently prepared reserves estimates to conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4 10(a)(2) of Regulation S X. RSC issued a report on our proved reserves at December 31, 2017, based upon its evaluation. RSC's primary economic assumptions in estimates included an ability to sell Jubilee, TEN and our equity method investment field oil at a price of $54.52, $54.44 and $53.89, respectively, and certain levels of future capital expenditures. The assumptions, data, methods and precedents were appropriate for the purpose served by these reports, and RSC used all methods and procedures as it considered necessary under the circumstances to prepare the report.

Table of Contents

Technology used to establish proved reserves

Under the SEC rules, proved 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. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have proved effective by actual comparison of production from projects in the same reservoir interval, an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, RSC employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, production and injection data, electrical logs, radioactivity logs, acoustic logs, whole core analysis, sidewall core analysis, downhole pressure and temperature measurements, reservoir fluid samples, geochemical information, geologic maps, seismic data, well test and interference pressure and rate data. Reserves attributable to undeveloped locations were estimated using performance from analogous wells with similar geologic depositional environments, rock quality, appraisal plans and development plans to assess the estimated ultimate recoverable reserves as a function of the original oil in place. These qualitative measures are benchmarked and validated against sound petroleum reservoir engineering principles and equations to estimate the ultimate recoverable reserves volume. These techniques include, but are not limited to, nodal analysis, material balance, and numerical flow simulation.

Internal controls over reserves estimation process

In our Reservoir Engineering team, we maintain an internal staff of petroleum engineering and geoscience professionals with significant international experience that contribute to our internal reserve and resource estimates. This team works closely with our independent petroleum engineers to ensure the integrity, accuracy and timeliness of data furnished in their reserve and resource estimation process. Our Reservoir Engineering team is responsible for overseeing the preparation of our reserves estimates and has over 100 combined years of industry experience among them with positions of increasing responsibility in engineering and evaluations. Each member of our team holds a minimum of Bachelor of Science degree in petroleum engineering or geology.

The RSC technical person primarily responsible for preparing the estimates set forth in the RSC reserves report incorporated herein is Mr. Guadalupe Ramirez. Mr. Ramirez has been practicing consulting petroleum engineering at RSC since 1981. Mr. Ramirez is a Licensed Professional Engineer in the State of Texas (No. 48318) and has over 35 years of practical experience in petroleum engineering. He graduated from Texas A&M University in 1976 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Ramirez meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

The Audit Committee provides oversight on the processes utilized in the development of our internal reserve and resource estimates on an annual basis. In addition, our Reservoir Engineering team meets with representatives of our independent reserve engineers to review our assets and discuss methods and assumptions used in preparation of the reserve and resource estimates. Finally, our senior management reviews reserve and resource estimates on an annual basis.

Table of Contents

Gross and Net Undeveloped and Developed Acreage

The following table sets forth certain information regarding the developed and undeveloped portions of our license areas as of December 31, 2017 for the countries in which we currently operate.

	Developed Area (Acres)		Undeveloped Area (Acres)		Total Area (Acres)	
	Gross	Net(1)	Gross	Net(1)	Gross	Net(1)
	(In thousands)					
Ghana						
Jubilee Unit	52	13	—	—	52	13
TEN	111	19	—	—	111	19
West Cape Three Points(2)	—	—	28	9	28	9
Deepwater Tano(2)	—	—	27	4	27	4
Equatorial Guinea(3)						
Block EG-21	—	—	617	247	617	247
Block S	—	—	308	123	308	123
Block W	—	—	557	223	557	223
Mauritania						
Block C6	—	—	1,063	298	1,063	298
Block C8	—	—	2,220	622	2,220	622
Block C12	—	—	1,273	356	1,273	356
Block C13	—	—	1,452	407	1,452	407
Block C18	—	—	3,268	490	3,268	490
Morocco						
Essaouira	—	—	2,171	1,628	2,171	1,628
Sao Tome and Principe						
Block 5	—	—	703	316	703	316
Block 6	—	—	1,241	559	1,241	559
Block 11	—	—	2,209	1,436	2,209	1,436
Block 12	—	—	1,738	782	1,738	782
Senegal						
Cayar Offshore Profond	—	—	1,350	405	1,350	405
Saint Louis Offshore Profond	—	—	1,650	495	1,650	495
Suriname						
Block 42	—	—	1,526	509	1,526	509
Block 45	—	—	1,267	633	1,267	633
Total Kosmos	163	32	24,668	9,542	24,831	9,574
Equity method investment(4)	65	28	—	—	65	28
Total	228	60	24,668	9,542	24,896	9,602

(1) Net acreage based on Kosmos' participating interest, before the exercise of any options or back in rights, except for our net acreage associated with the Jubilee and TEN fields, which are after the exercise of options or back in rights. Our net acreage in Ghana may be affected by any redetermination of interests in the Jubilee Unit.

(2) The Exploration Period of the WCTP petroleum contract and DT petroleum contract has expired. The undeveloped area reflected in the table above represents acreage within our discovery areas that were not subject to relinquishment on the expiry of the Exploration Period.

Table of Contents

(3) Ratification of the petroleum contracts by the President of Equatorial Guinea is required before the petroleum contracts become effective.
(4) Represents our 50% interest in KTIPI.

Productive Wells

Productive wells consist of producing wells and wells capable of production, including wells awaiting connections. For wells that produce both oil and gas, the well is classified as an oil well. The following table sets forth the number of productive oil and gas wells in which we held an interest at December 31, 2017:

	Productive Oil Wells		Productive Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Ghana—Jubilee Unit	26	6.24	—	—	26	6.24
Ghana—Ten(1)	11	1.87	—	—	11	1.87
Kosmos Total	37	8.11	—	—	37	8.11
Equity Method Investment(2)(3)	96	38.78	—	—	96	38.78
Total	133	46.89	—	—	133	46.89

(1) Of the 11 productive wells, 10 (gross) or 1.70 (net) have multiple completions within the wellbore.
(2) Represents our 50% interest in KTIPI.
(3) Of the 96 productive wells, 6 (gross) or 2.42 (net) have multiple completions within the wellbore.

Table of Contents

Drilling activity

The results of oil and natural gas wells drilled and completed for each of the last three years were as follows:

	Exploratory and Appraisal Wells(1)						Development Wells(1)							
	Productive(2)		Dry(3)		Total		Productive(2)		Dry(3)		Total		Total	Total
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Year Ended December 31, 2017														
Ghana														
Jubilee Unit	—	—	—	—	—	—	—	—	—	—	—	—	—	—
TEN	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Mauritania														
Block C8	—	—	1	0.28	1	0.28	—	—	—	—	—	—	1	0.28
Block C12	—	—	1	0.28	1	0.28	—	—	—	—	—	—	1	0.28
Total	—	—	2	0.56	2	0.56	—	—	—	—	—	—	2	0.56
Year Ended December 31, 2016														
Ghana														
Jubilee Unit	—	—	—	—	—	—	—	—	—	—	—	—	—	—
TEN	—	—	—	—	—	—	7	1.19	—	—	7	1.19	7	1.19
Total	—	—	—	—	—	—	7	1.19	—	—	7	1.19	7	1.19
Year Ended December 31, 2015														
Ghana														
Jubilee Unit	—	—	—	—	—	—	3	0.72	—	—	3	0.72	3	0.72
TEN	—	—	—	—	—	—	4	0.68	—	—	4	0.68	4	0.68
Morocco (including Western Sahara)														
Cap Boujdour	—	—	1	0.55	1	0.55	—	—	—	—	—	—	1	0.55
Total	—	—	1	0.55	1	0.55	7	1.40	—	—	7	1.40	8	1.95

(1) As of December 31, 2017, nine exploratory and appraisal wells have been excluded from the table until a determination is made if the wells have found proved reserves. Also excluded from the table are 14 development wells awaiting completion. These wells are shown as "Wells Suspended or Waiting on Completion" in the table below.

(2) A productive well is an exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas producing well. Productive wells are included in the table in the year they were determined to be productive, as opposed to the year the well was drilled.

(3) A dry well is an exploratory or development well that is not a productive well. Dry wells are included in the table in the year they were determined not to be a productive well, as opposed to the year the well was drilled.

Table of Contents

The following table shows the number of wells that are in the process of being drilled or are in active completion stages, and the number of wells suspended or waiting on completion as of December 31, 2017.

	Actively Drilling or Completing				Wells Suspended or Waiting on Completion			
	Exploration		Development		Exploration		Development	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Ghana								
Jubilee Unit	—	—	—	—	—	—	9	2.17
West Cape Three Points	—	—	—	—	2	0.62	—	—
TEN	—	—	—	—	—	—	5	0.85
Deepwater Tano	—	—	—	—	1	0.18	—	—
Mauritania								
C8	—	—	—	—	3	0.84	—	—
Senegal								
Saint Louis Offshore Profond	1	0.30	—	—	1	0.30	—	—
Cayar Profond	—	—	—	—	2	0.60	—	—
Total	1	0.30	—	—	9	2.54	14	3.02

Domestic Supply Requirements

Many of our petroleum contracts or, in some cases, the applicable law governing such agreements, grant a right to the respective host country to purchase certain amounts of oil/gas produced pursuant to such agreements at international market prices for domestic consumption. In addition, in connection with the approval of the Jubilee Phase 1 PoD, the Jubilee Field partners agreed to provide the first 200 Bcf of natural gas produced from the Jubilee Field Phase 1 development to GNPC at no cost. As of December 31, 2017, 78 Bcf of the 200 Bcf of natural gas has been provided.

Significant License Agreements

Below is a discussion concerning the petroleum contracts governing our current drilling and production operations.

West Cape Three Points Block

As a result of the approval of the GJFFDP by the Ghana Ministry of Energy in October 2017, operatorship for the Mahogany and Teak discoveries transferred to Tullow in February 2018 and are now included in the Jubilee Unit. Kosmos is required to pay a fixed royalty of 5% and a sliding scale royalty (“additional oil entitlement”) which escalates as the nominal project rate of return increases. These royalties are to be paid in kind or, at the election of the government of Ghana, in cash. A corporate tax rate of 35% is applied to profits at a country level.

The WCTP petroleum contract has a duration of 30 years from its effective date (July 2004). However, in July 2011, at the end of the seven year Exploration Period, parts of the WCTP Block on which we had not declared a discovery area, were not in a development and production area, or were not in the Jubilee Unit, were relinquished (“WCTP Relinquishment Area”). We maintain rights to the Akasa discovery within the WCTP Block as the WCTP petroleum contract remains in effect after the end of the Exploration Period. We and our WCTP Block partners have certain rights to negotiate a new petroleum contract with respect to the WCTP Relinquishment Area. We and our WCTP Block partners, the Ghana Ministry of Energy and GNPC have agreed such WCTP petroleum contract rights to negotiate extend from July 21, 2011 until such time as either a new petroleum contract is negotiated and entered into with us or we decline to match a bona fide third party offer GNPC may receive for the WCTP Relinquishment Area.

Table of Contents

Deepwater Tano Block

Tullow is the operator of the Deepwater Tano Block. Under the DT petroleum contract, GNPC exercised its option to acquire an additional paying interest of 5% in the commercial discovery with respect to the Jubilee Field development and the TEN Fields development. Kosmos is required to pay a fixed royalty of 5% and an additional oil entitlement which escalates as the nominal project rate of return increases. These royalties are to be paid in kind or, at the election of the government of Ghana, in cash. A corporate tax rate of 35% is applied to profits at a country level.

In January 2013, at the end of the seven year Exploration Period, parts of the DT Block on which we had not declared a discovery area, were not in a development and production area, or were not in the Jubilee Unit, were relinquished ("DT Relinquishment Area"). Our existing Wawa discovery within the DT Block was not subject to relinquishment upon expiration of the Exploration Period of the DT petroleum contract, as the DT petroleum contract remains in effect after the end of the Exploration Period while commerciality is being determined. Pursuant to our DT petroleum contract, we and our DT Block partners have certain rights to negotiate a new petroleum contract with respect to the DT Relinquishment Area until such time as either a new petroleum contract is negotiated and entered into with us or we decline to match a bona fide third party offer GNPC may receive for the DT Relinquishment Area.

The Ghanaian Petroleum Exploration and Production Law of 1984 (PNDCL 84) (the "1984 Ghanaian Petroleum Law") and the WCTP and DT petroleum contracts form the basis of our exploration, development and production operations on the WCTP and DT blocks. Pursuant to these petroleum contracts, most significant decisions, including PoDs and annual work programs, for operations other than exploration and appraisal, must be approved by a joint management committee, consisting of representatives of certain block partners and GNPC. Certain decisions require unanimity.

Jubilee Field Unitization

The Jubilee Field, discovered by the Mahogany 1 well in June 2007, covers an area within both the WCTP and DT Blocks. It was agreed the Jubilee Field would be unitized for optimal resource recovery. A Pre-Unit Agreement was agreed to between the contractors groups of the WCTP and DT Blocks in 2008, with a more comprehensive unit agreement, the UUOA, agreed to in 2009 which govern each party's respective rights and duties in the Jubilee Unit. Tullow is the Unit Operator, while Kosmos was the Technical Operator for the initial development of the Jubilee Field. The Jubilee Unit holders' interests are subject to redetermination in accordance with the terms of the UUOA. Although the Jubilee Field is unitized, Kosmos' participating interests in each block outside the boundary of the Jubilee Unit remain the same. Our Unit interest is 24.1% subject to redetermination of the participating interests pursuant to the terms of the UUOA. Our paying interest on development activities is 26.9%.

Morocco Exploration Agreements

Effective April 2, 2012, we entered into the Essaouria Offshore Petroleum Agreement as operator. During 2016, our partner BP, relinquished their participating interest in the petroleum contract. The Moroccan national oil company, ONHYM's, participating interest is carried by the block partners proportionately during the exploration phase. We are required to pay a 10% royalty on oil produced in water depths of 200 meters or less (the first 300,000 tons produced are exempt from royalty) and 7% royalty on oil produced in water depths deeper than 200 meters (the first 500,000 tons produced are exempt from royalty). These royalties are to be paid in kind or, at the election of the government of Morocco, in cash. A corporate tax rate of 30% is applied to profits at the license level following a 10 year tax holiday post first production. The term of the Essaouria Offshore Permits, beginning November 8, 2011, is eight years and includes an initial exploration period of two years and six months followed by the first extension period of four years and six months and the second extension period of one year. We are currently in the first extension period of the exploration permit, which as a result of an amendment in October 2016, ends in November 2018. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

Suriname Exploration Agreements

In December 2011, we signed a petroleum contract covering Offshore Block 42 located offshore Suriname and are the operator. Staatsolie Maatschappij Suriname N.V. ("Staatsolie"), Suriname's national oil company, has the option to back into the contract with an interest of not more than 10% upon approval of a development plan. The Block 42 petroleum contract provides for us to recover our share of expenses incurred ("cost recovery oil") and our share of remaining oil ("profit oil"). Cost recovery oil is apportioned to the contractor from up to 80% of gross production prior to profit oil being split between the government of Suriname and the contractor. Profit oil is then apportioned based upon "R factor" tranches, where the R factor is cumulative net revenues divided by cumulative net investment. A corporate tax rate of 36% is applied to profits. We are in the initial period of

Table of Contents

the exploration phase, which has been extended and ends in September 2018. There are two renewal periods consisting of three years for the first renewal period and two years for the second renewal period. Each renewal period carries a one well drilling obligation. In the event of commercial success, the duration of the contract will be 30 years from the effective date or 25 years from governmental approval of a plan of development, whichever is longer. Block 42 comprises approximately 1.5 million acres (approximately 6,176 square kilometers).

In December 2011, we signed a petroleum contract covering Offshore Block 45 located offshore Suriname and are the operator. Staatsolie will be carried through the exploration and appraisal phases and has the option to back into the petroleum contract with an interest of not more than 15% upon approval of a development plan. The Block 45 petroleum contract provides for us to recover our share of expenses incurred ("cost recovery oil") and our share of remaining oil ("profit oil"). Cost recovery oil is apportioned to the contractor from up to 80% of gross production prior to profit oil being split between the government of Suriname and the contractor. Profit oil is then apportioned based upon "R factor" tranches, where the R factor is cumulative net revenues divided by cumulative net investment. A corporate tax rate of 36% is applied to profits. We are currently in the initial period of the exploration phase, which has been extended and ends in September 2018. Following the initial period, there are two renewal periods consisting of two years each. Each renewal period carries a one well drilling obligation. In the event of commercial success, the duration of the contract will be 30 years from the effective date or 25 years from governmental approval of a plan of development, whichever is longer.

Mauritania Exploration Agreements

Effective June 2012, we entered into three petroleum contracts covering offshore Mauritania blocks C8, C12 and C13 with the Islamic Republic of Mauritania. We provide technical exploration services to BP, the operator. The Mauritanian national oil company, SMHPM, currently has a 10% carried participating interest during the exploration period only. Should a commercial discovery be made, SMHPM's 10% carried interest is extinguished and SMHPM will have an option to acquire a participating interest between 10% and 14%. SMHPM will pay its portion of development and production costs in a commercial development. Cost recovery oil is apportioned to the contractor from up to 55% of total production prior to profit oil being split between the government of Mauritania and the contractor. Profit oil is then apportioned based upon "R factor" tranches, where the R factor is cumulative net revenues divided by the cumulative investment. At the election of the government of Mauritania, the government may receive its share of production in cash or in kind. A corporate tax rate of 27% is applied to profits at the license level. The terms of exploration periods of these Offshore Blocks are all ten years and include an initial exploration period of four years followed by the first extension period of three years and the second extension period of three years. Kosmos is currently in the first extension period of the blocks, expiring in June 2019. In the event of commercial success, we have the right to develop and produce oil for 25 years and gas for 30 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

In September 2017, we acquired a 15% non-operated participating interest in Block C18 offshore Mauritania. Based on the terms of the agreement, we will reimburse a portion of past and interim period costs and partially carry Tullow's share of a planned 3D seismic program. We will also pay Tullow $2.5 million by the end of the initial phase of the exploration period for additional carry of seismic and other joint account costs. SMHPM currently has a 10% carried participating interest during the exploration period. Should a commercial discovery be made, SMHPM's 10% carried interest is extinguished and SMHPM will have an option to acquire a participating interest between 10% and 15%. SMHPM will pay its portion of development and production costs in a commercial development. The terms of exploration periods are ten years and include an initial exploration period of seven years from the effective date (June 15, 2012), including extensions received prior to our entry into Block 18. The first exploration phase includes a 7,600 square kilometer 3D seismic requirement, which is currently being acquired.

Senegal Exploration Agreements

In June 2015, we entered the first renewal of the exploration period for the Senegal Blocks Contract Areas, which lasts for three years. The exploration phase of each contract area may be extended to December 2020 at our election subject to our fulfilling specific work obligations including an exploration well in the final period of two and one half years.

In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for at least one additional period of 10 years under certain circumstances.

Sao Tome and Principe Exploration Agreements

In late 2015 and early 2016, Kosmos entered into petroleum contracts for Blocks 5, 6, 11 and 12 in Sao Tome and Principe.

Table of Contents

In Block 11, the Agencia Nacional Do Petroleo De Sao Tome E Príncipe ("ANP STP") has a carried 15% participating interest. The production sharing contract was awarded in July 2014, and provides for an initial exploration period of eight years with possible extensions and includes a first phase exploration period of four years followed by the second phase of two years and the third phase of two years. The block is currently in the first phase, expiring in July 2019 after receiving a one year extension in November 2017. The next exploration phases are subject to fulfillment of specific work obligations. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 20 years from the approval of a field development program by ANP STP, which may be extended for additional periods of five years until all commercial hydrocarbons have been depleted.

In Block 6, ANP STP has a carried 10% participating interest. The production sharing contract was awarded in October 2015, and provides for an initial exploration period of eight years with possible extensions and includes a first phase exploration period of four years followed by the second phase of two years and the third phase of two years. The block is currently in the first phase, expiring in November 2019. The next exploration phases are subject to fulfillment of specific work obligations. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 20 years from the approval of a field development program by ANP STP, which may be extended for additional periods of five years until all commercial hydrocarbons have been depleted.

In Block 5 and Block 12, ANP STP has a 15% and 12.5% carried interest , respectively. The production sharing contracts were awarded in May 2012 and February 2016, respectively, and provide for an initial exploration period of eight years with possible extensions and include a first phase exploration period of four years followed by the second phase of two years and the third phase of two years. The blocks are currently in the first phase, expiring in May of 2019 and February 2020, respectively (the first phase of Block 5 has been extended twice for a total of 3 years). The next exploration phases are subject to fulfillment of specific work obligations. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 20 years from the approval of a field development program by ANP STP, which may be extended for additional periods of five years until all commercial hydrocarbons have been depleted.

Equatorial Guinea Exploration Agreements

In October 2017, we entered into petroleum contracts covering Blocks EG-21, S, and W with the Republic of Equatorial Guinea. Ratification of the petroleum contracts by the President of Equatorial Guinea is expected in early 2018. Upon ratification, we will have an 80% participating interest and will be the operator in all three blocks, but pursuant to an agreement with Trident we expect to assign a 40% participating interest in the blocks to Trident. The Equatorial Guinean national oil company, Guinea Equatorial De Petroleos ("GEPetrol"), currently has a 20% carried participating interest during the exploration period. Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest. The petroleum contracts cover approximately 6,000 square kilometers, with a first exploration period of five years from the date of notification of ratification by the President of Equatorial Guinea. The first exploration period consists of two sub-periods of three and two years, respectively. The first exploration sub-period work program includes an approximately 6,000 square kilometer 3D seismic acquisition requirement across the three blocks.

Cote d'Ivoire

In December 2017, we entered into petroleum contracts covering Blocks CI-526, CI-602, CI-603, CI-707 and CI-708 with the Government of Cote d'Ivoire, and we are the operator. The Cote d'Ivoire national oil company, PETROCI Holding ("PETROCI"), currently has a 10% carried interest. The petroleum contracts cover approximately 17,000 square kilometers, with a first exploration period of three years with two possible extensions of three years each. The next exploration phases are subject to fulfillment of specific work programs. The first exploration period work program includes a 12,000 square kilometer 3D seismic acquisition across the five blocks.

Sales and Marketing

As provided under the UUOA and the WCTP and DT petroleum contracts, we are entitled to lift and sell our share of the Jubilee and TEN production as are the other Jubilee Unit and TEN partners. We have entered into an agreement with an oil marketing agent to market our share of the Jubilee and TEN fields oil, and we approve the terms of each

sale proposed by such agent. We do not anticipate entering into any long term sales agreements at this time.
In December 2017, we signed the TEN Associated-Gas Gas Sales Agreement (TAG GSA) and we expect to begin exporting TEN associated gas to shore in the second quarter of 2018. The TAG GSA provides for a sales price of $0.50 per mmbtu.

Table of Contents

As provided under the Production Sharing Contract for Block G, KTEGI is entitled to lift and sell our share of the Ceiba Blend production as are the other Ceiba Blend partners. KTEGI has entered into an agreement with an oil marketing agent to market our share of the Ceiba Blend oil, and we approve the terms of each sale proposed by such agent. We do not anticipate entering into any long term sales agreements at this time.

There are a variety of factors which affect the market for oil, including the proximity and capacity of transportation facilities, demand for oil both within the local market and beyond, the marketing of competitive fuels and the effects of government regulations on oil production and sales. Our revenue can be materially affected by current economic conditions and the price of oil. However, based on the current demand for crude oil and the fact that alternative purchasers are available, we believe that the loss of our marketing agent and/or any of the purchasers identified by our marketing agent would not have a long term material adverse effect on our financial position or results of operations.

Competition

The oil and gas industry is competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring licenses. 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 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.

Historically, we have also been affected by competition for drilling rigs and the availability of related equipment. Higher commodity prices generally increase the demand for drilling rigs, supplies, services, equipment and crews. Shortages of, or increasing costs for, experienced drilling crews and equipment and services may restrict our ability to drill wells and conduct our operations.

The oil and gas industry as a whole has experienced an extended decline in crude oil prices. Dated Brent crude, the benchmark for our oil sales, ranged from approximately $44 to $67 per barrel during 2017. Excluding the impact of hedges, our realized price for 2017 was $53.73 per barrel. We believe lower prices will generally result in greater availability of assets and necessary equipment. However the impacts on the industry from a competitive perspective are not entirely known at this point.

Title to Property

Other than as specified in this annual report on Form 10 K, we believe that we have satisfactory title to our oil and natural gas assets in accordance with standards generally accepted in the international oil and gas industry. Our licenses are subject to customary royalty and other interests, liens under operating agreements and other burdens, restrictions and encumbrances customary in the oil and gas industry that we believe do not materially interfere with the use of, or affect the carrying value of, our interests.

Environmental Matters

General

We are subject to various stringent and complex international, foreign, federal, state and local environmental, health and safety laws and regulations governing matters including the emission and discharge of pollutants into the ground, air or water; the generation, storage, handling, use and transportation of regulated materials; and the health and safety of our employees. These laws and regulations may, among other things:

- require the acquisition of various permits before operations commence;
- enjoin some or all of the operations or facilities deemed not in compliance with permits;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling, production and transportation activities;
- limit, cap, tax or otherwise restrict emissions of GHG and other air pollutants or otherwise seek to address or minimize the effects of climate change;

Table of Contents

- limit or prohibit drilling activities in certain locations lying within protected or otherwise sensitive areas; and
- require measures to mitigate or remediate pollution, including pollution resulting from our block partners' or our contractors' operations.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. Compliance with these laws can be costly; the regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. We cannot assure you that we have been or will be at all times in compliance with such laws, or that environmental laws and regulations will not change or become more stringent in the future in a manner that could have a material adverse effect on our financial condition and results of operations.

Moreover, public interest in the protection of the environment continues to increase. Offshore drilling in some areas has been opposed by environmental groups and, in other areas, has been restricted. Our operations could be adversely affected to the extent laws or regulations are enacted or other governmental action is taken that prohibits or restricts offshore drilling or imposes environmental requirements that increase costs to the oil and gas industry in general, such as more stringent or costly waste handling, disposal or cleanup requirements or financial responsibility and assurance requirements.

Capping and Containment

We entered into an agreement with a third party service provider for it to supply subsea capping and containment equipment on a global basis. The equipment includes capping stacks, debris removal, subsea dispersant and auxiliary equipment. The equipment meets industry accepted standards and can be deployed by air cargo and other conventional means to suit multiple application scenarios. We also developed an emergency response plan and response organization to prepare and demonstrate our readiness to respond to a subsea well control incident.

Oil Spill Response

To complement our agreement discussed above for subsea capping and containment equipment, we became a charter member of the Global Dispersant Stockpile. The dispersant stockpile, which is managed by Oil Spill Response Limited ("OSRL") of Southampton, United Kingdom ("UK"), an oil spill response contractor, consists of 5,000 cubic meters of dispersant strategically located at OSRL bases around the world. The total volume of the stockpile located at the OSRL bases is calculated to provide members with the ability to respond to a major spill incident.

Mauritania and Senegal (Operated and Non-operated)

Kosmos maintains Oil Spill Contingency Plans ("OSCP") to support our drilling operations in countries where we operate. The plans are based on the principle of "Tiered Response" to oil spills ("Guide to Tiered Response and Preparedness", IPIECA Report Series, Volume 14, 2007). A Tier 1 spill is defined as a small-scale operational incident which can be addressed with resources that are immediately available to us. A Tier 2 spill is a larger incident which would need to be addressed with regionally based shared resources. A Tier 3 spill is a large incident which would require assistance from national or world-wide spill co-operatives. Under OSCPs, emergency response teams may be activated to respond to oil spill incidents. The OSCPs call for Tier 1 spill equipment at our shorebases in Nouakchott, Mauritania and Dakar, Senegal to respond to a harbor or shoreline incident in the area. We also maintain dispersant spraying capabilities in the field to respond to an offshore incident. We have access to additional Tier 2 and Tier 3 equipment from OSRL's Southampton, UK location.

Suriname

Kosmos intends to conduct drilling operations in Suriname in 2018. An OSCP has been completed per the previously mentioned "Guide to Tiered Response and Preparedness". Kosmos plans to maintain it's dispersant spraying capabilities in the field. We expect to have access to additional Tier 2 and Tier 3 equipment from OSRL's Americas base in Ft Lauderdale, FL.

Ghana (Non-operated)

Tullow, our partner and the operator of the Jubilee Unit and the TEN fields, maintains an OSCP covering the Jubilee Field and Deepwater Tano Block. Under the OSCPs, emergency response teams may be activated to respond to oil spill incidents. Tullow has access to OSRL's oil spill response services comprising technical expertise and assistance, including access to response equipment and dispersant spraying systems. Tullow maintains lease agreements with

OSRL for Tier 1 and Tier 2 packages of oil spill response equipment. Tier 1 equipment, which is stored in “ready to go trailers” for effective mobilization and deployment, includes booms and ancillaries, recovery systems, pumps and delivery systems, oil storage containers, personal protection

Table of Contents

equipment, sorbent materials, hand tools, containers and first aid equipment. Tier 2 equipment consists of larger boom and oil recovery systems, pump and delivery systems and auxiliary equipment such as generators and lighting sets, and is also containerized and pre packed in trailers and ready for mobilization.

Tullow has additional response capability to handle an offshore Tier 1 response. Further, our membership in the West and Central Africa Aerial Surveillance and Dispersant Spraying Service (“WACAF”) gives us access to aircraft for surveillance and spraying of dispersant, which is administered by OSRL for a Tier 2 offshore response. The aircraft is based at the Kotoka International Airport in Accra, Ghana with a contractual response time, loaded with dispersant, of six hours. Additional stockpiles of dispersant are maintained in Takoradi, Ghana. Although the above arrangement is in place, we can make no assurance that these resources will be available or respond in a timely manner as intended, perform as designed or be able to fully contain or cap any oil spill, blow out or uncontrolled flow of hydrocarbons. While a Tier 3 incident is not expected in Ghana, in the case of a Tier 3 incident, Tullow would engage the services of OSRL.

Per common industry practice, under agreements governing the terms of use of the drilling rigs contracted by us or our block partners, the drilling rig contractors indemnify us and our block partners in respect of pollution and environmental damage originating above the surface of the water and from such drilling rig contractor’s property, including their drilling rig and other related equipment. Furthermore, pursuant to the terms of the operating agreements for blocks in which we or our block partners are currently drilling, except in certain circumstances, each block partner is responsible for its share of liabilities in proportion to its participating interest incurred as a result of pollution and environmental damage, containment and clean up activities, loss or damage to any well, loss of oil or natural gas resulting from a blowout, crater, fire, or uncontrolled well, loss of stored oil and natural gas, as well as for plugging or bringing under control any well. We maintain insurance coverage typical of the industry in the areas we operate in; these include property damage insurance, loss of production insurance, wreck removal insurance, control of well insurance, general liability including pollution liability to cover pollution from wells and other operations. We also participate in an insurance coverage program for the Jubilee FPSO. Our insurance is carried in amounts typical for the industry relative to our size and operations and in accordance with our contractual and regulatory obligations.

Equatorial Guinea (Operated and Non-operated)

Kosmos recently entered into a joint venture in Equatorial Guinea through the acquisition KTIPI, which includes the Ceiba Field and Okume Complex. Our current plan is to maintain the existing capabilities to respond to a production spill. Before beginning any drilling campaign, the spill response assets will be evaluated to determine if any new equipment is necessary.

Certain Bermuda Law Considerations

As a Bermuda exempted company, we are subject to regulation in Bermuda. Among other things, we must comply with the provisions of the Bermuda Companies Act regulating the payment of dividends and making of distributions from contributed surplus.

We have been designated by the Bermuda Monetary Authority as a non resident for Bermuda exchange control purposes. This designation allows us to engage in transactions in currencies other than the Bermuda dollar, and there are no restrictions on our ability to transfer funds (other than funds denominated in Bermuda dollars) in and out of Bermuda or to pay dividends to United States residents who are holders of our common shares.

Under Bermuda law, “exempted” companies are companies formed for the purpose of conducting business outside Bermuda from a principal place of business in Bermuda. As an exempted company, we may not, without a license or consent granted by the Minister of Finance, participate in certain business transactions, including transactions involving Bermuda landholding rights and the carrying on of business of any kind for which we are not licensed in Bermuda.

Employees

As of December 31, 2017, we had approximately 280 employees. None of these employees are represented by labor unions or covered by any collective bargaining agreement. We believe that relations with our employees are satisfactory.

Corporate Information

We were incorporated pursuant to the laws of Bermuda as Kosmos Energy Ltd. in January 2011 to become a holding company for Kosmos Energy Holdings. Kosmos Energy Holdings was formed as an exempted company limited by guarantee pursuant to the laws of the Cayman Islands in March 2004. Pursuant to the terms of a corporate reorganization that was completed simultaneously with the closing of our initial public offering, all of the interests in Kosmos Energy Holdings were exchanged for

Table of Contents

newly issued common shares of Kosmos Energy Ltd. and as a result, Kosmos Energy Holdings became a wholly owned subsidiary of Kosmos Energy Ltd.

We maintain a registered office in Bermuda at Clarendon House, 2 Church Street, Hamilton HM 11, Bermuda. The telephone number of our registered offices is (441) 295 5950. Our U.S. subsidiary maintains its headquarters at 8176 Park Lane, Suite 500, Dallas, Texas 75231 and its telephone number is (214) 445 9600.

Available Information

Kosmos is listed on the New York Stock Exchange and London Stock Exchange and our common shares are traded under the symbol KOS. We file or furnish annual, quarterly and current reports, proxy statements and other information with the SEC as well as the London Stock Exchange's Regulatory News Service ("LSE RNS"). The public may read and copy any reports, statements or other information at the SEC’s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information about the operation of the public reference room by calling the SEC at 1 800 SEC 0330. In addition, the SEC maintains a website at http://www.sec.gov that contains documents we file electronically with the SEC. The LSE RNS maintains a website at http://www.londonstockexchange.com that contains documents we file electronically with the LSE RNS.

The Company also maintains an internet website under the name www.kosmosenergy.com. The information on our website is not incorporated by reference into this annual report on Form 10 K and should not be considered a part of this annual report on Form 10 K. Our website is included as an inactive technical reference only. We make available, free of charge, on our website, our annual report on Form 10 K, quarterly reports on Form 10 Q, current reports on Form 8 K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after such reports are electronically filed with, or furnished to, the SEC.

Table of Contents

Item 1A. Risk Factors

You should consider and read carefully all of the risks and uncertainties described below, together with all of the other information contained in this report, including the consolidated financial statements and the related notes included in "Item 8. Financial Statements and Supplementary Data." If any of the following risks actually occurs, our business, business prospects, financial condition, results of operations or cash flows could be materially adversely affected. The risks below are not the only ones we face. Additional risks not currently known to us or that we currently deem immaterial may also adversely affect us.

Risks Relating to the Oil and Natural Gas Industry and Our Business

We have limited proved reserves and areas that we decide to drill may not yield oil and natural gas in commercial quantities or quality, or at all.

We have limited proved reserves. A portion of our oil and natural gas assets consists of discoveries without approved PoDs and with limited well penetrations, as well as identified yet unproven prospects based on available seismic and geological information that indicates the potential presence of hydrocarbons. However, the areas we decide to drill may not yield oil or natural gas in commercial quantities or quality, or at all. Many of our current discoveries and all of our prospects are in various stages of evaluation that will require substantial additional analysis and interpretation. Even when properly used and interpreted, 2D and 3D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. Accordingly, we do not know if any of our discoveries or prospects will contain oil or natural gas in sufficient quantities or quality to recover drilling and completion costs or to be economically viable. Even if oil or natural gas is found on our discoveries or prospects in commercial quantities, construction costs of gathering lines, subsea infrastructure and floating production systems and transportation costs may prevent such discoveries or prospects from being economically viable, and approval of PoDs by various regulatory authorities, a necessary step in order to develop a commercial discovery, may not be forthcoming. Additionally, the analogies drawn by us using available data from other wells, more fully explored discoveries or producing fields may not prove valid with respect to our drilling prospects. We may terminate our drilling program for a discovery or prospect if data, information, studies and previous reports indicate that the possible development of a discovery or prospect is not commercially viable and, therefore, does not merit further investment. If a significant number of our discoveries or prospects do not prove to be successful, our business, financial condition and results of operations will be materially adversely affected.

The deepwater offshore Ghana, an area in which we focus a substantial amount of our development efforts, has only recently been considered economically viable for hydrocarbon production due to the costs and difficulties involved in drilling for oil at such depths and the relatively recent discovery of commercial quantities of oil in the region. Likewise, our deepwater offshore Cote d'Ivoire, Equatorial Guinea, Mauritania, Morocco, Sao Tome and Principe, Senegal, and Suriname licenses have not yet proved to be economically viable production areas. We have limited proved reserves, and we may not be successful in developing additional commercially viable production from our other discoveries and prospects.

We face substantial uncertainties in estimating the characteristics of our unappraised discoveries and our prospects.

In this report we provide numerical and other measures of the characteristics of our discoveries and prospects. These measures may be incorrect, as the accuracy of these measures is a function of available data, geological interpretation and judgment. To date, a limited number of our prospects have been drilled. Any analogies drawn by us from other wells, discoveries or producing fields may not prove to be accurate indicators of the success of developing proved reserves from our discoveries and prospects. Furthermore, we have no way of evaluating the accuracy of the data from analog wells or prospects produced by other parties which we may use.

It is possible that few or none of our wells to be drilled will find accumulations of hydrocarbons in commercial quality or quantity. Any significant variance between actual results and our assumptions could materially affect the quantities of hydrocarbons attributable to any particular prospect.

Drilling wells is speculative, often involving significant costs that may be more than we estimate, and may not result in any discoveries or additions to our future production or reserves. Any material inaccuracies in drilling costs, estimates or underlying assumptions will materially affect our business.

Exploring for and developing hydrocarbon reserves involves a high degree of technical, operational and financial risk, which precludes definitive statements as to the time required and costs involved in reaching certain objectives. The budgeted costs of planning, drilling, completing and operating wells are often exceeded and can increase significantly when drilling costs rise due to a tightening in the supply of various types of oilfield equipment and related services or unanticipated geologic conditions.

Table of Contents

Before a well is spud, we incur significant geological and geophysical (seismic) costs, which are incurred whether or not a well eventually produces commercial quantities of hydrocarbons or is drilled at all. Drilling may be unsuccessful for many reasons, including geologic conditions, weather, cost overruns, equipment shortages and mechanical difficulties or force majeure events. Exploratory wells bear a much greater risk of loss than development wells. In the past we have experienced unsuccessful drilling efforts, having drilled dry holes. Furthermore, the successful drilling of a well does not necessarily result in the commercially viable development of a field or be indicative of the potential for the development of a commercially viable field. A variety of factors, including geologic and market related, can cause a field to become uneconomic or only marginally economic. A lack of drilling opportunities or projects that cease production may cause us to incur significant costs associated with an idle rig and/or related services, particularly if we cannot contract out rig slots to other parties. Many of our prospects that may be developed require significant additional exploration, appraisal and development, regulatory approval and commitments of resources prior to commercial development. In addition, a successful discovery would require significant capital expenditure in order to develop and produce oil and natural gas, even if we deemed such discovery to be commercially viable. See "—Our business plan requires substantial additional capital, which we may be unable to raise on acceptable terms or at all in the future, which may in turn limit our ability to develop our exploration, appraisal, development and production activities." In the areas in which we operate, we face higher above ground risks necessitating higher expected returns, the requirement for increased capital expenditures due to a general lack of infrastructure and underdeveloped oil and gas industries, and increased transportation expenses due to geographic remoteness, which either require a single well to be exceptionally productive, or the existence of multiple successful wells, to allow for the development of a commercially viable field. See "—Our operations may be adversely affected by political and economic circumstances in the countries in which we operate." Furthermore, if our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our business operations as proposed and could be forced to modify our plan of operation.

Development drilling may not result in commercially productive quantities of oil and gas reserves.

Our exploration success has provided us with major development projects on which we are moving forward, and any future exploration discoveries will also require significant development efforts to bring to production. We must successfully execute our development projects, including development drilling, in order to generate future production and cash flow. However, development drilling is not always successful and the profitability of development projects may change over time.

For example, in new development projects available data may not allow us to completely know the extent of the reservoir or choose the best locations for drilling development wells. A development well we drill may be a dry hole or result in noncommercial quantities of hydrocarbons. All costs of development drilling and other development activities are capitalized, even if the activities do not result in commercially productive quantities of hydrocarbon reserves. This puts a property at higher risk for future impairment if commodity prices decrease or operating or development costs increase.

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has identified and scheduled drilling locations on our license areas over a multi year period. Our ability to drill and develop these locations depends on a number of factors, including the availability of equipment and capital, approval by block partners and regulators, seasonal conditions, oil prices, assessment of risks, costs and drilling results. The final determination on whether to drill any of these locations will be dependent upon the factors described elsewhere in this report as well as, to some degree, the results of our drilling activities with respect to our established drilling locations. Because of these uncertainties, we do not know if the drilling locations we have identified will be drilled within our expected timeframe or at all or if we will be able to economically produce hydrocarbons from these or any other potential drilling locations. As such, our actual drilling activities may be materially different from our current expectations, which could adversely affect our results of operations and financial condition.

A substantial or extended decline in both global and local oil and natural gas prices may adversely affect our business, financial condition and results of operations.

The prices that we will receive for our oil and natural gas will significantly affect our revenue, profitability, access to capital and future growth rate. Historically, the oil and natural gas markets have been volatile and will likely continue to be volatile in the future. Oil prices experienced significant and sustained declines in the past few years and will likely continue to be volatile in the future. The prices that we will receive for our production and the levels of our production depend on numerous factors. These factors include, but are not limited to, the following:

- changes in supply and demand for oil and natural gas;

- the actions of the Organization of the Petroleum Exporting Countries;
- speculation as to the future price of oil and natural gas and the speculative trading of oil and natural gas futures contracts;
- global economic conditions;
- political and economic conditions, including embargoes in oil producing countries or affecting other oil producing activities, particularly in the Middle East, Africa, Russia and Central and South America;
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil inventories and oil refining capacities;
- weather conditions and natural or man made disasters;
- technological advances affecting energy consumption;
- governmental regulations and taxation policies;
- proximity and capacity of transportation facilities;
- the development and exploitation of alternative fuels or energy sources;
- the price and availability of competitors' supplies of oil and natural gas; and
- the price, availability or mandated use of alternative fuels or energy sources.

Lower oil prices may not only reduce our revenues but also may limit the amount of oil that we can produce economically. A substantial or extended decline in oil and natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Under the terms of our various petroleum contracts, we are contractually obligated to drill wells and declare any discoveries in order to retain exploration and production rights. In the competitive market for our license areas, failure to drill these wells or declare any discoveries may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas, which may include certain of our prospects.

In order to protect our exploration and production rights in our license areas, we must meet various drilling and declaration requirements. In general, unless we make and declare discoveries within certain time periods specified in our various petroleum agreements and licenses, our interests in the undeveloped parts of our license areas may lapse. Should the prospects yield discoveries, we cannot assure you that we will not face delays in the appraisal and development of these prospects or otherwise have to relinquish these prospects. The costs to maintain petroleum contracts over such areas may fluctuate and may increase significantly since the original term, and we may not be able to renew or extend such petroleum contracts on commercially reasonable terms or at all. Our actual drilling activities may therefore materially differ from our current expectations, which could adversely affect our business.

Under these petroleum contracts, we have work commitments to perform exploration and other related activities. Failure to do so may result in our loss of the licenses. As of December 31, 2017, we have unfulfilled drilling obligations in one of our Mauritania petroleum contracts. In certain other petroleum contracts, we are in the initial exploration phase, some of which have certain obligations that have yet to be fulfilled. Over the course of the next several years, we may choose to enter into the next phase of those petroleum contracts which will likely include firm obligations to drill wells. Failure to execute our obligations may result in our loss of the licenses.

The Exploration Period of each of the WCTP and DT petroleum contracts has expired. Pursuant to the terms of such petroleum contracts, while we and our respective block partners have certain rights to negotiate new petroleum contracts with respect to the WCTP Relinquishment Area and DT Relinquishment Area, we cannot assure you that we will determine to enter any such new petroleum contracts. For each of our petroleum contracts, we cannot assure you that any renewals or extensions will be granted or whether any new agreements will be available on commercially reasonable terms, or, in some cases, at all. For additional detail regarding the status of our operations with respect to our various petroleum contracts, please see "Item 1. Business—Operations by Geographic Area."

The inability of one or more third parties who contract with us to meet their obligations to us may adversely affect our financial results.

We may be liable for certain costs if third parties who contract with us are unable to meet their commitments under such agreements. We are currently exposed to credit risk through joint interest receivables from our block and/or unit partners. If any of our partners in the blocks or unit in which we hold interests are unable to fund their share of the exploration and development expenses, we may be liable for such costs. In the past, certain of our WCTP and DT Block partners have not paid their share of block costs in the time frame required by the joint operating agreements for these blocks. This has resulted in such party being in default, which in return requires Kosmos and its non defaulting block partners to pay their proportionate share of the defaulting party's costs during the default period. Should a default not be cured, Kosmos could be required to pay its share of the defaulting party's costs going forward.

In addition, we contract with third parties to conduct drilling and related services on our development projects and exploration prospects. Such third parties may not perform the services they provide us on schedule or within budget. Furthermore, the drilling equipment, facilities and infrastructure owned and operated by the third parties we contract with is highly complex and subject to malfunction and breakdown. Any malfunctions or breakdowns may be outside our control and result in delays, which could be substantial. Any delays in our drilling campaign caused by equipment, facility or equipment malfunction or breakdown could materially increase our costs of drilling and cause an adverse effect on our business, financial position and results of operations.

Our principal exposure to credit risk will be through receivables resulting from the sale of our oil, which we currently sell to an energy marketing company, and to cover our commodity derivatives contracts. The inability or failure of our significant customers or counterparties to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. Joint interest receivables arise from our block partners. The inability or failure of third parties we contract with to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. We are unable to predict sudden changes in creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited and we could incur significant financial losses.

The unit partners' respective interests in the Jubilee Unit are subject to redetermination and our interests in such unit may decrease as a result.

The interests in and development of the Jubilee Field are governed by the terms of the UUOA. The parties to the UUOA, the collective interest holders in each of the WCTP and DT Blocks, initially agreed that interests in the Jubilee Unit will be shared equally, with each block deemed to contribute 50% of the area of such unit. The respective interests in the Jubilee Unit were therefore initially determined by the respective interests in such contributed block interests. Pursuant to the terms of the UUOA, the percentage of such contributed interests is subject to a process of redetermination once sufficient development work has been completed in the unit. The initial redetermination process was completed on October 14, 2011. As a result of the initial redetermination process, the tract participation was determined to be 54.4% for the WCTP Block and 45.6% for the DT Block. Our Unit Interest (participating interest in the Jubilee Unit) was increased from 23.5% to 24.1%. An additional redetermination could occur sometime if requested by a party that holds greater than a 10% interest in the Jubilee Unit. We cannot assure you that any redetermination pursuant to the terms of the UUOA will not negatively affect our interests in the Jubilee Unit or that such redetermination will be satisfactorily resolved.

We are not, and may not be in the future, the operator on all of our license areas and do not, and may not in the future, hold all of the working interests in certain of our license areas. Therefore, we have reduced control over the timing of exploration or development efforts, associated costs, and the rate of production of any non operated and to an extent, any non wholly owned, assets.

As we carry out our exploration and development programs, we have arrangements with respect to existing license areas and may have agreements with respect to future license areas that result in a greater proportion of our license areas being operated by others. Currently, we are not the operator of the Jubilee Unit, the TEN fields or Ceiba and

Okume and do not hold operatorship in other offshore blocks. In addition, our agreements with BP and Chevron contemplate that operatorship will be transitioned fully to these companies in our Cote d'Ivoire (BP) and Suriname (Chevron) acreage upon a commercial discovery. As a result, we may have limited ability to exercise influence over the operations of the discoveries or prospects operated by our block or unit partners, or which are not wholly owned by us, as the case may be. Dependence on block or unit partners could prevent us from realizing our target returns for those discoveries or prospects. Further, because we do not have majority ownership in all of our properties,

Table of Contents

we may not be able to control the timing, or the scope, of exploration or development activities or the amount of capital expenditures and, therefore, may not be able to carry out one of our key business strategies of minimizing the cycle time between discovery and initial production. The success and timing of exploration and development activities will depend on a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- if the activity is operated by one of our block partners, the operator's expertise and financial resources;
- approval of other block partners in drilling wells;
- the scheduling, pre design, planning, design and approvals of activities and processes;
- selection of technology; and
- the rate of production of reserves, if any.

This limited ability to exercise control over the operations on our license areas may cause a material adverse effect on our financial condition and results of operations.

Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is technically complex. It requires interpretations of available technical data and many assumptions, including those relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this report. See "Item 1. Business—Our Reserves" for information about our estimated oil and natural gas reserves and the present value of our net revenues at a 10% discount rate ("PV 10") and Standardized Measure of discounted future net revenues (as defined herein) as of December 31, 2017.

In order to prepare our estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with the SEC requirements, we have based the estimated discounted future net revenues from our proved reserves on the 12 month unweighted arithmetic average of the first day of the month price for the preceding twelve months, adjusted for an anticipated market premium, without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas assets will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- derivative transactions;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

Table of Contents

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas assets will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

Actual future prices and costs may differ materially from those used in the present value estimates included in this report. If oil prices decline by $1.00 per Bbl from prices used in calculating such estimates, then the PV 10 and the Standardized Measure as of December 31, 2017 would each decrease by approximately $33.9 million. Oil prices have recently experienced significant volatility. See "Item 1. Business—Our Reserves."

We are dependent on certain members of our management and technical team.

Our performance and success largely depend on the ability, expertise, judgment and discretion of our management and the ability of our technical team to identify, discover, evaluate and develop reserves. The loss or departure of one or more members of our management and technical team could be detrimental to our future success. Additionally, a significant amount of shares in Kosmos held by members of our management and technical team has vested. There can be no assurance that our management and technical team will remain in place. If any of these officers or other key personnel resigns or becomes unable to continue in their present roles and is not adequately replaced, our results of operations and financial condition could be materially adversely affected. Our ability to manage our growth, if any, will require us to continue to train, motivate and manage our employees and to attract, motivate and retain additional qualified personnel. Competition for these types of personnel is intense, and we may not be successful in attracting, assimilating and retaining the personnel required to grow and operate our business profitably.

Our business plan requires substantial additional capital, which we may be unable to raise on acceptable terms or at all in the future, which may in turn limit our ability to develop our exploration, appraisal, development and production activities.

We expect our capital outlays and operating expenditures to be substantial as we expand our operations. Obtaining seismic data, as well as exploration, appraisal, development and production activities entail considerable costs, and we may need to raise substantial additional capital through additional debt financing, strategic alliances or future private or public equity offerings if our cash flows from operations, or the timing of, are not sufficient to cover such costs.

Our future capital requirements will depend on many factors, including:

- the scope, rate of progress and cost of our exploration, appraisal, development and production activities;
- the success of our exploration, appraisal, development and production activities;
- oil and natural gas prices;
- our ability to locate and acquire hydrocarbon reserves;
- our ability to produce oil or natural gas from those reserves;
- the terms and timing of any drilling and other production related arrangements that we may enter into;
- the cost and timing of governmental approvals and/or concessions; and
- the effects of competition by larger companies operating in the oil and gas industry.

We do not currently have any commitments for future external funding beyond the capacity of our commercial debt facility and revolving credit facility. Additional financing may not be available on favorable terms, or at all. Even if we succeed in selling additional equity securities to raise funds, at such time the ownership percentage of our existing shareholders would be diluted, and new investors may demand rights, preferences or privileges senior to those of existing shareholders. If we raise additional capital through debt financing, the financing may involve covenants that restrict our business activities. If we choose to farm out interests in our licenses, we would dilute our ownership interest subject to the farm out and any potential value resulting therefrom, and may lose operating control or influence over such license areas.

Assuming we are able to commence exploration, appraisal, development and production activities or successfully exploit our licenses during the exploratory term, our interests in our licenses (or the development/production area of such licenses as they existed at that time, as applicable) could extend beyond the term set for the exploratory phase of the license to a fixed period or life of production, depending on the jurisdiction. If we are unable to meet our well commitments and/or declare commerciality of

Table of Contents

the prospective areas of our licenses during this time, we may be subject to significant potential forfeiture of all or part of the relevant license interests. If we are not successful in raising additional capital, we may be unable to continue our exploration and production activities or successfully exploit our license areas, and we may lose the rights to develop these areas. See "—Under the terms of our various license agreements, we are contractually obligated to drill wells and declare any discoveries in order to retain exploration and production rights. In the competitive market for our license areas, failure to declare any discoveries and thereby establish development areas may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas, which may include certain of our prospects."

All of our proved reserves, oil production and cash flows from operations are currently associated with our licenses offshore Ghana and Equatorial Guinea. Should any event occur which adversely affects such proved reserves, oil production and cash flows from these licenses, including, without limitation, any event resulting from the risks and uncertainties outlined in this "Risk Factors" section, our business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures may be materially and adversely affected.

We may be required to take write downs of the carrying values of our oil and natural gas assets as a result of decreases in oil and natural gas prices, and such decreases could result in reduced availability under our corporate revolver and commercial debt facility.

We capitalize costs to acquire, find and develop our oil and natural gas properties under the successful efforts accounting method. Under such method, we are required to perform impairment tests on our assets periodically and whenever events or changes in circumstances warrant a review of our assets. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of appraisal and development plans, production data, oil and natural gas prices, economics and other factors, we may be required to write down the carrying value of our oil and natural gas assets. A write down constitutes a non cash charge to earnings. As a result of the recent drop in oil and natural gas prices, we may incur future write downs and charges should prices remain at low levels.

In addition, our borrowing base under the commercial debt facility is subject to periodic redeterminations. We could be forced to repay a portion of our borrowings under the commercial debt facility due to redeterminations of our borrowing base. Redeterminations may occur as a result of a variety of factors, including oil and natural gas commodity price assumptions, assumptions regarding future production from our oil and natural gas assets, operating costs and tax burdens or assumptions concerning our future holdings of proved reserves. If we are forced to do so, we may not have sufficient funds to make such repayments. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

We may not be able to commercialize our interests in any natural gas produced from our license areas.

The development of the market for natural gas in our license areas is in its early stages. Currently the infrastructure to transport and process natural gas on commercial terms is limited and the expenses associated with constructing such infrastructure ourselves may not be commercially viable given local prices currently paid for natural gas. Accordingly, there may be limited or no value derived from any natural gas produced from our license areas.

In Ghana, we currently produce associated gas from the Jubilee and TEN fields. A gas pipeline from the Jubilee Field has been constructed to transport such natural gas for processing and sale. However, we granted the Government of Ghana the first 200 Bcf of natural gas exported from the Jubilee Field to shore at zero cost. Through December 31, 2017, the Jubilee partners have provided approximately 78 Bcf from the Jubilee Field to Ghana. Thus, in Ghana, it is forecasted to be a few years before we are able to commercialize the Jubilee Field natural gas. We do not currently book proved gas reserves associated with natural gas sales from the Jubilee Field in Ghana. However, we expect to book gas reserves upon finalization and execution of a gas sales agreement for such Jubilee Field natural gas that will have a price associated with it. A gas pipeline from the TEN fields to the Jubilee Field was completed in the first quarter of 2017 to transport associated natural gas as well as non-associated natural gas for processing and sale. We finalized the TAG GSA , and as a result, we booked proved gas reserves for the associated natural gas from the TEN fields in Ghana. If and when a gas sales agreement and the related infrastructure are in place for the TEN fields non-associated gas, a portion of the remaining gas may be recognized as reserves.

In Mauritania and Senegal, we plan to export the majority of our gas resource to the liquefied natural gas (“LNG”) market. However, that plan is contingent on making a final investment decision on our gas discoveries and constructing the necessary infrastructure to produce, liquefy and transport the gas to the market as well as finding an LNG purchaser. Additionally, such plans are contingent upon receipt of required partner and government approvals.

Table of Contents

Our inability to access appropriate equipment and infrastructure in a timely manner may hinder our access to oil and natural gas markets or delay our oil and natural gas production.

Our ability to market our oil and natural gas production will depend substantially on the availability and capacity of processing facilities, oil and LNG tankers and other infrastructure, including FPSOs, owned and operated by third parties. Our failure to obtain such facilities on acceptable terms could materially harm our business. We also rely on continuing access to drilling rigs suitable for the environment in which we operate. The delivery of drilling rigs may be delayed or cancelled, and we may not be able to gain continued access to suitable rigs in the future. We may be required to shut in oil and natural gas wells because of the absence of a market or because access to processing facilities may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver the production to market, which could cause a material adverse effect on our financial condition and results of operations. In addition, the shutting in of wells can lead to mechanical problems upon bringing the production back on line, potentially resulting in decreased production and increased remediation costs.

Additionally, the future exploitation and sale of associated and non associated natural gas and liquids and LNG will be subject to timely commercial processing and marketing of these products, which depends on the contracting, financing, building and operating of infrastructure by third parties. The Government of Ghana completed the construction and connection of a gas pipeline from the Jubilee Field and the pipeline between the Jubilee and TEN fields to transport such natural gas to the mainland for processing and sale was completed in the first quarter of 2017. However, the uptime of the facility in future periods is not known. In the absence of the continuous removal of large quantities of natural gas it is anticipated that we will either need to flare such natural gas in order to maintain crude oil production or reduce crude oil production. Currently, we have not been issued an amended permit from the Ghana EPA to flare natural gas produced from the Jubilee Field in substantial quantities. If we are unable to resolve potential issues related to the continuous removal of associated natural gas in large quantities, our oil production will be negatively impacted.

We are subject to numerous risks inherent to the exploration and production of oil and natural gas.

Oil and natural gas exploration and production activities involve many risks that a combination of experience, knowledge and interpretation may not be able to overcome. Our future will depend on the success of our exploration and production activities and on the development of an infrastructure that will allow us to take advantage of our discoveries. Additionally, many of our license areas are located in deepwater, which generally increases the capital and operating costs, chances of delay, planning time, technical challenges and risks associated with oil and natural gas exploration and production activities. See "— Our offshore and deepwater operations involve special risks that could adversely affect our results of operation." As a result, our oil and natural gas exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable oil and natural gas production. Our decisions to purchase, explore or develop discoveries, prospects or licenses will depend in part on the evaluation of seismic data through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations.

Furthermore, the marketability of expected oil and natural gas production from our discoveries and prospects will also be affected by numerous factors. These factors include, but are not limited to, market fluctuations of prices (such as recent significant declines in oil and natural gas prices), proximity, capacity and availability of drilling rigs and related equipment, qualified personnel and support vessels, processing facilities, transportation vehicles and pipelines, equipment availability, access to markets and government regulations (including, without limitation, regulations relating to prices, taxes, royalties, allowable production, domestic supply requirements, importing and exporting of oil and natural gas, the ability to flare or vent natural gas, health and safety matters, environmental protection and climate change). The effect of these factors, individually or jointly, may result in us not receiving an adequate return on invested capital.

In the event that our currently undeveloped discoveries and prospects are developed and become operational, they may not produce oil and natural gas in commercial quantities or at the costs anticipated, and our projects may cease production, in part or entirely, in certain circumstances. Discoveries may become uneconomic as a result of an increase in operating costs to produce oil and natural gas. Our actual operating costs and rates of production may differ materially from our current estimates. Moreover, it is possible that other developments, such as increasingly strict environmental, climate change, health and safety laws and regulations and enforcement policies thereunder and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities, delays, an inability to complete the development of our discoveries or the abandonment of such discoveries, which could cause a material adverse effect on our financial condition and results of operations.

We are subject to drilling and other operational and environmental risks and hazards.

The oil and natural gas business involves a variety of risks, including, but not limited to:

Table of Contents

- fires, blowouts, spills, cratering and explosions;
- mechanical and equipment problems, including unforeseen engineering complications. For example, following a February 2016 inspection of the turret area of the Jubilee field FPSO, by SOFEC, Inc., the original turret manufacturer, a potential issue was identified with the turret bearing. As a precautionary measure, additional operating procedures to monitor the turret bearing and reduce the degree of rotation of the vessel have been put in place until this situation has been remediated;
- uncontrolled flows or leaks of oil, well fluids, natural gas, brine, toxic gas or other pollutants or hazardous materials;
- gas flaring operations;
- marine hazards with respect to offshore operations;
- formations with abnormal pressures;
- pollution, environmental risks, and geological problems; and
- weather conditions and natural or man made disasters.

These risks are particularly acute in deepwater drilling and exploration. Any of these events could result in loss of human life, significant damage to property, environmental or natural resource damage, impairment, delay or cessation of our operations, lower production rates, adverse publicity, substantial losses and civil or criminal liability. We expect to maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events, whether or not covered by insurance, could have a material adverse effect on our financial position and results of operations.

The development schedule of oil and natural gas projects, including the availability and cost of drilling rigs, equipment, supplies, personnel and oilfield services, is subject to delays and cost overruns.

Historically, some oil and natural gas development projects have experienced delays and capital cost increases and overruns due to, among other factors, the unavailability or high cost of drilling rigs and other essential equipment, supplies, personnel and oilfield services, as well as mechanical and technical issues. The cost to develop our projects has not been fixed and remains dependent upon a number of factors, including the completion of detailed cost estimates and final engineering, contracting and procurement costs. Our construction and operation schedules may not proceed as planned and may experience delays or cost overruns. Any delays may increase the costs of the projects, requiring additional capital, and such capital may not be available in a timely and cost effective fashion.

Our offshore and deepwater 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, such as capsizing, sinking, collisions and damage or loss to pipeline, subsea or other facilities or from weather conditions. 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.

Deepwater exploration generally involves greater operational and financial risks than exploration in shallower waters. Deepwater drilling generally requires 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. If we participate in the development of new subsea infrastructure and use floating production systems to transport oil from producing wells, these operations 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. For example, we have experienced mechanical issues in the Jubilee Field, including failures of its gas and water injection facilities on the FPSO, and are currently working to remediate the turret bearing issue on the FPSO. This resulted in the need to implement new operating and offloading procedures, including the use of tug boats for heading control and a dynamically positioned (“DP”) shuttle tanker and storage vessel for offloading. The equipment downtime caused by these mechanical issues negatively impacted oil production during the year.

In addition, Kosmos and its Jubilee partners determined that the risers of the FPSO have experienced increased levels of stress compared to their original design basis, which may cause these risers to suffer operational fatigue earlier than originally anticipated. The Jubilee partnership is currently assessing the condition of the risers and, if required, plans for remediation work of this riser issue which may include instrumentation of the risers to assess further operational fatigue or replacement of all or a part of one or more risers. Such remediation efforts may negatively impact oil production, and/or result in additional expenses.

Table of Contents

Furthermore, deepwater operations generally, and operations in Africa and South America, in particular, lack the physical and oilfield service infrastructure present in other regions. As a result, a significant amount of time may elapse between a deepwater discovery and the marketing of the associated oil and natural gas, increasing both the financial and operational risks involved with these operations. Because of the lack and high cost of this infrastructure, further discoveries we may make in Africa and South America may never be economically producible.

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, and have a significant negative impact on our earnings, cash flows, liquidity, financial position, and stock price.

We have had disagreements with the Republic of Ghana and the Ghana National Petroleum Corporation regarding certain of our rights and responsibilities under the WCTP and DT Petroleum Agreements.

Multiple discovered fields and a significant portion of our proved reserves are located offshore Ghana. The WCTP petroleum contract, the DT petroleum contract and the UUOA cover the two blocks and the Jubilee and TEN fields that form the basis of our current operations in Ghana. Pursuant to these petroleum contracts, most significant decisions, including our plans for development and annual work programs, must be approved by GNPC, the Petroleum Commission and/or Ghana's Ministry of Energy. We have previously had disagreements with the Ministry of Energy and GNPC regarding certain of our rights and responsibilities under these petroleum contracts, the 1984 Ghanaian Petroleum Law and the Internal Revenue Act, 2000 (Act 592) (the "Ghanaian Tax Law"). These included disagreements over sharing information with prospective purchasers of our interests, pledging our interests to finance our development activities, potential liabilities arising from discharges of small quantities of drilling fluids into Ghanaian territorial waters, the failure to approve the proposed sale of our Ghanaian assets, assertions that could be read to give rise to taxes payable under the Ghanaian Tax Law, failure to approve PoDs relating to certain discoveries offshore Ghana and the relinquishment of certain exploration areas on our licensed blocks offshore Ghana. The resolution of certain of these disagreements required us to pay agreed settlement costs to GNPC and/or the government of Ghana.

There can be no assurance that future disagreements will not arise with any host government and/or national oil companies that may have a material adverse effect on our exploration or development activities, our ability to operate, our rights under our licenses and local laws or our rights to monetize our interests.

The geographic locations of our licenses in Africa and South America subject us to an increased risk of loss of revenue or curtailment of production from factors specifically affecting those areas.

Our current exploration licenses are located in Africa and South America. Some or all of these licenses could be affected should any region experience any of the following factors (among others):

- severe weather, natural or man made disasters or acts of God;
- delays or decreases in production, the availability of equipment, facilities, personnel or services;
- delays or decreases in the availability of capacity to transport, gather or process production;
- military conflicts, civil unrest or political strife; and/or
- international border disputes.

For example, oil and natural gas operations in our license areas in Africa and South America may be subject to higher political and security risks than those operations under the sovereignty of the United States. We plan to maintain insurance coverage for only a portion of the risks we face from doing business in these regions. There also may be certain risks covered by insurance where the policy does not reimburse us for all of the costs related to a loss. Further, as many of our licenses are concentrated in the same geographic area, a number of our licenses could experience the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of licenses.

Table of Contents

Our operations may be adversely affected by political and economic circumstances in the countries in which we operate.

Oil and natural gas exploration, development and production activities are subject to political and economic uncertainties (including but not limited to changes in energy policies or the personnel administering them), changes in laws and policies governing operations of foreign based companies, expropriation of property, cancellation or modification of contract rights, revocation of consents or approvals, obtaining various approvals from regulators, foreign exchange restrictions, currency fluctuations, royalty increases and other risks arising out of foreign governmental sovereignty, as well as risks of loss due to civil strife, acts of war, guerrilla activities, terrorism, acts of sabotage, territorial disputes and insurrection. In addition, we are subject both to uncertainties in the application of the tax laws in the countries in which we operate and to possible changes in such tax laws (or the application thereof), each of which could result in an increase in our tax liabilities. These risks may be higher in the developing countries in which we conduct a majority of our activities, as it is the case in Ghana, where the Ghanaian Revenue Authority (the "GRA") has disputed certain tax deductions we have claimed in prior fiscal years' Ghanaian tax returns as non allowable under the terms of the Ghanaian Petroleum Income Tax Law, as well as non payment of certain transactional taxes. Our operations in these areas increase our exposure to risks of war, local economic conditions, political disruption, civil disturbance, expropriation, piracy, tribal conflicts and governmental policies that may:

- disrupt our operations;
- require us to incur greater costs for security;
- restrict the movement of funds or limit repatriation of profits;
- lead to U.S. government or international sanctions; or
- limit access to markets for periods of time.

Some countries in the geographic areas where we operate have experienced political instability in the past or are currently experiencing instability. Disruptions may occur in the future, and losses caused by these disruptions may occur that will not be covered by insurance. Consequently, our exploration, development and production activities may be substantially affected by factors which could have a material adverse effect on our results of operations and financial condition. Furthermore, in the event of a dispute arising from non U.S. operations, we may be subject to the exclusive jurisdiction of courts outside the United States or may not be successful in subjecting non U.S. persons to the jurisdiction of courts in the United States or international arbitration, which could adversely affect the outcome of such dispute.

Our operations may also be adversely affected by laws and policies of the jurisdictions, including the jurisdictions where our oil and gas operating activities are located as well as the United States, the United Kingdom, Bermuda and the Cayman Islands and other jurisdictions in which we do business, that affect foreign trade and taxation. Changes in any of these laws or policies or the implementation thereof could materially and adversely affect our financial position, results of operations and cash flows.

The oil and gas industry, including the acquisition of exploratory licenses, is intensely competitive and many of our competitors possess and employ substantially greater resources than us.

The international oil and gas industry is highly competitive in all aspects, including the exploration for, and the development of, new license areas. We operate in a highly competitive environment for acquiring exploratory licenses and hiring and retaining trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than us, which can be particularly important in the areas in which we operate. These companies may be better able to withstand the financial pressures of unsuccessful drilling efforts, sustained periods of volatility in financial markets and generally adverse global and industry wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which could adversely affect our competitive position. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable licenses and to consummate transactions in a highly competitive environment. Also, there is substantial competition for available capital for investment in the oil and gas industry. As a result of these and other factors, we may not be able to compete successfully in an intensely competitive industry, which could cause a material adverse effect on our results of operations and financial condition.

47

Table of Contents

Participants in the oil and gas industry are subject to numerous laws, regulations, and other legislative instruments that can affect the cost, manner or feasibility of doing business.

Exploration and production activities in the oil and gas industry are subject to local laws and regulations. We may be required to make large expenditures to comply with governmental laws and regulations, particularly in respect of the following matters:

- licenses for drilling operations;
- tax increases, including retroactive claims;
- unitization of oil accumulations;
- local content requirements (including the mandatory use of local partners and vendors); and
- safety, health and environmental requirements, liabilities and obligations, including those related to remediation, investigation or permitting.

Under these and other laws and regulations, we could be liable for personal injuries, property damage and other types of damages. Failure to comply with these laws and regulations also 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, or their interpretations could change, in ways that could substantially increase our costs. These risks may be higher in the developing countries in which we conduct a majority of our operations, where there could be a lack of clarity or lack of consistency in the application of these laws and regulations. Any resulting liabilities, penalties, suspensions or terminations could have a material adverse effect on our financial condition and results of operations. For example, Ghana’s Parliament has enacted the Petroleum Revenue Management Act, the Petroleum Commission Act of 2011, and the 2016 Ghanaian Petroleum Law. There can be no assurance that these laws will not seek to retroactively, either on their face or as interpreted, modify the terms of the agreements governing our license interests in Ghana, including the WCTP and DT petroleum contracts and the UUOA, require governmental approval for transactions that effect a direct or indirect change of control of our license interests or otherwise affect our current and future operations in Ghana. Any such changes may have a material adverse effect on our business. We also cannot assure you that government approval will not be needed for direct or indirect transfers of our petroleum agreements or interests thereunder based on existing legislation.

We are subject to numerous health, safety and environmental laws and regulations which may result in material liabilities and costs.

We are subject to various international, foreign, federal, state and local health, safety and environmental laws and regulations governing, among other things, the emission and discharge of pollutants into the ground, air or water, the generation, storage, handling, use, transportation and disposal of regulated materials and the health and safety of our employees, contractors and communities in which our assets are located. We are required to obtain environmental permits from governmental authorities for our operations, including drilling permits for our wells. We have not been or may not be at all times in complete compliance with these permits and laws and regulations to which we are subject, and there is a risk such requirements could change in the future or become more stringent. If we violate or fail to comply with such requirements, we could be fined or otherwise sanctioned by regulators, including through the revocation of our permits or the suspension or termination of our operations. If we fail to obtain, maintain or renew permits in a timely manner or at all (due to opposition from partners, community or environmental interest groups, governmental delays or other reasons), or if we face additional requirements imposed as a result of changes in or enactment of laws or regulations, such failure to obtain, maintain or renew permits or such changes in or enactment of laws or regulations could impede or affect our operations, which could have a material adverse effect on our results of operations and financial condition.

We, as an interest owner or as the designated operator of certain of our past, current and future interests, discoveries and prospects, could be held liable for some or all health, safety and environmental costs and liabilities arising out of our actions and omissions as well as those of our block partners, third party contractors, predecessors or other operators. To the extent we do not address these costs and liabilities or if we do not otherwise satisfy our obligations, our operations could be suspended or terminated. We have contracted with and intend to continue to hire third parties to perform services related to our operations. There is a risk that we may contract with third parties with unsatisfactory health, safety and environmental records or that our contractors may be unwilling or unable to cover any losses associated with their acts and omissions. Accordingly, we could be held liable for all costs and liabilities arising out of their acts or omissions, which could have a material adverse effect on our results of operations and financial condition.

Table of Contents

We are not fully insured against all risks and our insurance may not cover any or all health, safety or environmental claims that might arise from our operations or at any of our license areas. If a significant accident or other event occurs and is not covered by insurance, such accident or event could have a material adverse effect on our results of operations and financial condition.

Releases of regulated substances may occur and can be significant. Under certain environmental laws, we could be held responsible for all of the costs relating to any contamination at our current or former facilities and at any third party waste disposal sites used by us or on our behalf. In addition, offshore oil and natural gas exploration and production involves various hazards, including human exposure to regulated substances, which include naturally occurring radioactive, and other materials. As such, we could be held liable for any and all consequences arising out of human exposure to such substances or for other damage resulting from the release of any regulated or otherwise hazardous substances to the environment, property or to natural resources, or affecting endangered species.

In addition, we expect continued and increasing attention to climate change issues and emissions of GHGs, including methane (a primary component of natural gas) and carbon dioxide (a byproduct of oil and natural gas combustion). For example, in April 2016, 195 nations, including Ghana, Mauritania, Morocco, Sao Tome and Principe, Senegal, Suriname and the U.S., signed and officially entered into an international climate change accord (the “Paris Agreement”). The Paris Agreement calls for signatory countries to set their own GHG emissions targets, make these emissions targets more stringent over time and be transparent about the GHG emissions reporting and the measures each country will use to achieve its GHG targets. A long-term goal of the Paris Agreement is to limit global temperature increase to well below two degrees Celsius from temperatures in the pre-industrial era. The Paris Agreement is in effect a successor to the Kyoto Protocol, an international treaty aimed at reducing emissions of GHGs, to which various countries and regions, including Ghana, Mauritania, Morocco, Sao Tome and Principe, Senegal and Suriname, are parties. The Kyoto Protocol has been extended by amendment until 2020. It cannot be determined at this time what effect the Paris Agreement, and any related GHG emissions targets, regulations or other requirements, will have on our business, results of operations and financial condition. It also cannot be determined what impact the U.S.'s announced withdrawal from the Paris Agreement will have on international climate change regulation. This regulatory uncertainty, however, could result in a disruption to our business or operations. The physical impacts of climate change in the areas in which our assets are located or in which we otherwise operate, including through increased severity and frequency of storms, floods and other weather events, could adversely impact our operations or disrupt transportation or other process related services provided by our third party contractors.

Health, safety and environmental laws are complex, change frequently and have tended to become increasingly stringent over time. Our costs of complying with current and future climate change, health, safety and environmental laws, the actions or omissions of our block partners and third party contractors and our liabilities arising from releases of, or exposure to, regulated substances may adversely affect our results of operations and financial condition. See “Item 1. Business—Environmental Matters” for more information.

We face various risks associated with increased activism against oil and gas exploration and development activities.

Opposition toward oil and gas drilling and development activity has been growing globally. Companies in the oil and gas industry are often the target of activist efforts from both individuals and non governmental organizations regarding safety, human rights, climate change, environmental matters, sustainability, and business practices. Anti development activists are working to, among other things, delay or cancel certain operations such as offshore drilling and development.

Future activist efforts could result in the following:

- delay or denial of drilling permits;
- shortening of lease terms or reduction in lease size;
- restrictions or delays on our ability to obtain additional seismic data;
- restrictions on installation or operation of gathering or processing facilities;
- restrictions on the use of certain operating practices;
- legal challenges or lawsuits;
- damaging publicity about us;
- increased regulation;

Table of Contents

- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties.

Activism worldwide may increase if the Trump administration in the U.S. is perceived to be following, or actually follows, through on President Trump's campaign commitments to promote increased fossil fuel exploration and production in the U.S. Our need to incur costs associated with responding to these initiatives or complying with any resulting new legal or regulatory requirements resulting from these activities that are substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations.

We may be exposed to liabilities under the U.S. Foreign Corrupt Practices Act and other anti corruption laws, and any determination that we violated the U.S. Foreign Corrupt Practices Act or other such laws could have a material adverse effect on our business.

We are subject to the U.S. Foreign Corrupt Practices Act ("FCPA") and other laws that prohibit improper payments or offers of payments to foreign government officials and political parties for the purpose of obtaining or retaining business or otherwise securing an improper business advantage. In addition, the United Kingdom has enacted the Bribery Act of 2010, and we may be subject to that legislation under certain circumstances. We do business and may do additional business in the future in countries and regions in which we may face, directly or indirectly, corrupt demands by officials. We face the risk of unauthorized payments or offers of payments by one of our employees, contractors or consultants. Our existing safeguards and any future improvements may prove to be less than effective in preventing such unauthorized payments, and our employees and consultants may engage in conduct for which we might be held responsible. Violations of the FCPA may result in severe criminal or civil sanctions, and we may be subject to other liabilities, which could negatively affect our business, operating results and financial condition. In addition, the U.S. government may seek to hold us liable for successor liability for FCPA violations committed by companies in which we invest in (for example, by way of acquiring equity interests in, participating as a joint venture partner with, acquiring the assets of, or entering into certain commercial transactions with) or that we acquire.

Deterioration in the credit or equity markets could adversely affect us.

We have exposure to different counterparties. For example, we have entered or may enter into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, investment funds, and other institutions. These transactions expose us to credit risk in the event of default by our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill existing obligations to us and their willingness to enter into future transactions with us. We may have exposure to these financial institutions through any derivative transactions we have or may enter into. Moreover, to the extent that purchasers of our future production, if any, rely on access to the credit or equity markets to fund their operations, there is a risk that those purchasers could default in their contractual obligations to us if such purchasers were unable to access the credit or equity markets for an extended period of time.

We may incur substantial losses and become subject to liability claims as a result of future oil and natural gas operations, for which we may not have adequate insurance coverage.

We intend to maintain insurance against certain risks in the operation of the business we plan to develop and in amounts in which we believe to be reasonable. Such insurance, however, may contain exclusions and limitations on coverage or may not be available at a reasonable cost or at all. For example, we are not insured against political or terrorism risks. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition and results of operations. Further, even in instances where we maintain adequate insurance coverage, potential delays related to receipt of insurance proceeds as well as delays associated with the repair or rebuilding of damaged facilities could also materially and adversely affect our business, financial condition and results of operations.

We operate in a litigious environment.

Some of the jurisdictions within which we operate have proven to be litigious environments. Oil and gas companies, such as us, can be involved in various legal proceedings, such as title or contractual disputes, in the ordinary course of business.

Table of Contents

From time to time, we may become involved in various legal and regulatory proceedings arising in the normal course of business. We cannot predict the occurrence or outcome of these proceedings with certainty, and if we are unsuccessful in these disputes and any loss exceeds our available insurance, this could have a material adverse effect on our results of operations.

Because we maintain a diversified portfolio of assets overseas, the complexity and types of legal procedures with which we may become involved may vary, and we could incur significant legal and support expenses in different jurisdictions. If we are not able to successfully defend ourselves, there could be a delay or even halt in our exploration, development or production activities or other business plans, resulting in a reduction in reserves, loss of production and reduced cash flows. Legal proceedings could result in a substantial liability and/or negative publicity about us and adversely affect the price of our common shares. In addition, legal proceedings distract management and other personnel from their primary responsibilities.

We face various risks associated with global populism.

Globally, certain individuals and organizations are attempting to focus public attention on income distribution, wealth distribution, and corporate taxation levels, and implement income and wealth redistribution policies. These efforts, if they gain political traction, could result in increased taxation on individuals and/or corporations, as well as, potentially, increased regulation on companies and financial institutions. Our need to incur costs associated with responding to these developments or complying with any resulting new legal or regulatory requirements, as well as any potential increased tax expense, could increase our costs of doing business, reduce our financial flexibility and otherwise have a material adverse effect on our business, financial condition and results of our operations.

Slower global economic growth rates may materially adversely impact our operating results and financial position.

The recovery from the global economic crisis of 2008 and resulting recession has been slow and uneven. Market volatility and reduced consumer demand have increased economic uncertainty, and the current global economic growth rate is slower than what was experienced in the decade preceding the crisis. Many developed countries are constrained by long term structural government budget deficits and international financial markets and credit rating agencies are pressing for budgetary reform and discipline. This need for fiscal discipline is balanced by calls for continuing government stimulus and social spending as a result of the impacts of the global economic crisis. As major countries implement government fiscal reform, such measures, if they are undertaken too rapidly, could further undermine economic recovery, reducing demand and slowing growth. Impacts of the crisis have spread to China and other emerging markets, which have fueled global economic development in recent years, slowing their growth rates, reducing demand, and resulting in further drag on the global economy.

Global economic growth drives demand for energy from all sources, including hydrocarbons. A lower future economic growth rate is likely to result in decreased demand growth for our crude oil and natural gas production. A decrease in demand, notwithstanding impacts from other factors, could potentially result in lower commodity prices, which would reduce our cash flows from operations, our profitability and our liquidity and financial position.

Increased costs of capital could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Recent and continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

Our derivative activities could result in financial losses or could reduce our income.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we have and may in the future enter into derivative arrangements for a portion of our oil and natural gas production, including, but not limited to, puts, collars and fixed price swaps. In addition, we currently, and may in the future, hold swaps designed to hedge our interest rate risk. We do not currently designate any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value.

Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when:

Table of Contents

- production is less than the volume covered by the derivative instruments;
- the counter party to the derivative instrument defaults on its contract obligations; or
- there is an increase in the differential between the underlying price and actual prices received in the derivative instrument.

In addition, these types of derivative arrangements may limit the benefit we could receive from increases in the prices for oil and natural gas or beneficial interest rate fluctuations and may expose us to cash margin requirements.

Our commercial debt facility, revolving credit facility and indenture governing the Senior Notes contain certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals.

Our commercial debt facility, revolving credit facility and indenture governing the Senior Notes include certain covenants that, among other things, restrict:

- our investments, loans and advances and certain of our subsidiaries' payment of dividends and other restricted payments;
- our incurrence of additional indebtedness;
- the granting of liens, other than liens created pursuant to the commercial debt facility, revolving credit facility or the indenture governing the Senior Notes and certain permitted liens;
- mergers, consolidations and sales of all or a substantial part of our business or licenses;
- the hedging, forward sale or swap of our production of crude oil or natural gas or other commodities;
- the sale of assets (other than production sold in the ordinary course of business); and
- in the case of the commercial debt facility and the revolving credit facility, our capital expenditures that we can fund with the proceeds of our commercial debt facility, and revolving credit facility.

Our commercial debt facility, revolving credit facility and letter of credit facility require us to maintain certain financial ratios, such as debt service coverage ratios and cash flow coverage ratios. All of these restrictive covenants may limit our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our commercial debt facility, revolving credit facility and indenture governing the Senior Notes may be impacted by changes in economic or business conditions, our results of operations or events beyond our control. The breach of any of these covenants could result in a default under our commercial debt facility, revolving credit facility and indenture governing the Senior Notes, in which case, depending on the actions taken by the lenders thereunder or their successors or assignees, such lenders could elect to declare all amounts borrowed under our commercial debt facility, revolving credit facility and indenture governing the Senior Notes, together with accrued interest, to be due and payable and, in the case of the letter of credit facility, the breach of any of the applicable covenants could result in a default, in which case the cash collateral we are required to maintain under the letter of credit facility would increase from 75% to 100% of all outstanding letters of credit, and if such additional cash is not posted, the lenders thereunder could elect to declare all amounts outstanding thereunder, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders, successors or assignees could proceed against their collateral. If the indebtedness under our commercial debt facility, revolving credit facility, letter of credit facility and indenture governing the Senior Notes were to be accelerated, our assets may not be sufficient to repay in full such indebtedness. In addition, the limitations imposed by the commercial debt facility, the revolving credit facility, the letter of credit facility and the indenture governing the Senior Notes on our ability to incur additional debt and to take other actions might significantly impair our ability to obtain other financing.

Provisions of our Senior Notes could discourage an acquisition of us by a third party.

Certain provisions of the indenture governing the Senior Notes could make it more difficult or more expensive for a third party to acquire us, or may even prevent a third party from acquiring us. For example, upon the occurrence of a "change of control triggering event" (as defined in the indenture governing the Senior Notes), holders of the notes will have the right, at their option, to require us to repurchase all of their notes or any portion of the principal amount of such notes. By discouraging an acquisition of us by a third party, these provisions could have the effect of depriving the holders of our common shares of an opportunity to sell their common shares at a premium over prevailing market prices.

Table of Contents

Our level of indebtedness may increase and thereby reduce our financial flexibility.

At December 31, 2017, we had $800.0 million outstanding and $500.8 million of committed undrawn capacity under our commercial debt facility, subject to borrowing base availability. As of December 31, 2017, there were no borrowings outstanding under the Corporate Revolver and the undrawn availability was $400.0 million. As of December 31, 2017, there were eight outstanding letters of credit totaling $60.3 million under the letter of credit facility agreement and $525.0 million principal amount of Senior Notes outstanding. We also currently have, and may in the future incur, significant off balance sheet obligations. In the future, we may incur significant indebtedness in order to make investments or acquisitions or to explore, appraise or develop our oil and natural gas assets.

Our level of indebtedness could affect our operations in several ways, including the following:

- a significant portion or all of our cash flows, when generated, could be used to service our indebtedness;
- a high level of indebtedness could increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness will limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- a high level of indebtedness may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness could prevent us from pursuing;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- additional hedging instruments may be required as a result of our indebtedness;
- a high level of indebtedness may make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then outstanding bank borrowings; and
- a high level of indebtedness may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, risks associated with exploring for and producing oil and natural gas, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our indebtedness and future working capital, borrowings or equity financing may not be available to pay or refinance such indebtedness. Factors that will affect our ability to raise cash through an offering of our equity securities or a refinancing of our indebtedness include financial market conditions, the value of our assets and our performance at the time we need capital.

We are a holding company and our ability to make payments on our outstanding indebtedness, including our Senior Notes and our commercial debt facility, is dependent upon the receipt of funds from our subsidiaries by way of dividends, fees, interest, loans or otherwise.

We are a holding company, and our subsidiaries own all of our assets and conduct all of our operations. Accordingly, our ability to make payments of interest and principal on the Senior Notes and commercial debt facility will be dependent on the generation of cash flow by our subsidiaries and their ability to make such cash available to us, by dividend, debt repayment or otherwise. Unless they are guarantors, our subsidiaries will not have any obligation to pay amounts due on the notes or to make funds available for that purpose. Our subsidiaries may not be able to, or may not be permitted to, make distributions to enable us to make payments in respect of the Senior Notes or the commercial debt facility. Each subsidiary is a distinct legal entity and, under certain circumstances, legal and contractual restrictions may limit our ability to obtain cash from our subsidiaries. The indenture governing the Senior Notes limits the ability of our subsidiaries to incur consensual encumbrances or restrictions on their ability to pay dividends or make other intercompany payments to us, with significant qualifications and exceptions. In addition, the terms of the commercial debt facility limit the ability of the obligors thereunder, including our material operating subsidiaries that hold interests in our assets located offshore Ghana and their intermediate parent companies (other than Kosmos Energy Holdings) to provide cash to us through dividend, debt repayment or intercompany lending. In the event that we do not receive

Table of Contents

distributions from our subsidiaries, we may be unable to make required principal and interest payments on our indebtedness, including the Senior Notes and commercial debt facility.

We may be subject to risks in connection with acquisitions and the integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of prospects and licenses, reserves and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of these assets or businesses requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject assets that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the assets to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We may not be entitled to contractual indemnification for environmental liabilities and could acquire assets on an “as is” basis. Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management’s attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

If we fail to realize the anticipated benefits of a significant acquisition, our results of operations may be adversely affected.

The success of a significant acquisition (e.g., our investment in KTIPI) will depend, in part, on our ability to realize anticipated growth opportunities from combining the acquired assets or operations with those of ours. Even if a combination is successful, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices, increased interest expense associated with debt incurred or assumed in connection with the transaction, adverse changes in oil and gas industry conditions, or by risks and uncertainties relating to the exploratory prospects of the combined assets or operations, or an increase in operating or other costs or other difficulties, including the assumption of health, safety, and environmental or other liabilities in connection with the acquisition. If we fail to realize the benefits we anticipate from an acquisition, our results of operations may be adversely affected.

Our bye laws contain a provision renouncing our interest and expectancy in certain corporate opportunities, which could adversely affect our business or future prospects.

Our bye laws provide that, to the fullest extent permitted by applicable law, we renounce any right, interest or expectancy in, or in being offered an opportunity to participate in, any business opportunity that may be from time to time be presented to certain of our affiliates or any of their respective officers, directors, agents, shareholders, members, partners, affiliates and

Table of Contents

subsidiaries (other than us and our subsidiaries) or business opportunities that such parties participate in or desire to participate in, even if the opportunity is one that we might reasonably have pursued or had the ability or desire to pursue if granted the opportunity to do so, and no such person shall be liable to us for breach of any statutory, fiduciary, contractual or other duty, as a director or otherwise, by reason of the fact that such person pursues or acquires any such business opportunity, directs any such business opportunity to another person or fails to present any such business opportunity, or information regarding any such business opportunity, to us unless, in the case of any such person who is our director, such person fails to present any business opportunity that is expressly offered to such person solely in his or her capacity as our director.

As a result, our directors and certain of our affiliates and their respective affiliates may become aware, from time to time, of certain business opportunities, such as acquisition opportunities, and may direct such opportunities to other businesses in which they or their affiliates have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities. As a result, our renouncing of our interest and expectancy in any business opportunity that may be from time to time presented to our directors and certain of our affiliates and their respective affiliates could adversely impact our business or future prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours.

We receive certain beneficial tax treatment as a result of being an exempted company incorporated pursuant to the laws of Bermuda. Changes in that treatment could have a material adverse effect on our net income, our cash flow and our financial condition.

We are an exempted company incorporated pursuant to the laws of Bermuda and operate through subsidiaries in a number of countries throughout the world. Consequently, we are subject to changes in tax laws, treaties or regulations or the interpretation or enforcement thereof in the United States, Bermuda, Ghana, and other jurisdictions in which we or any of our subsidiaries operate or are resident. In the past, legislation has been introduced in the Congress of the United States that would reform the U.S. tax laws as they apply to certain non U.S. entities and operations, including legislation that would treat a foreign corporation as a U.S. corporation for U.S. federal income tax purposes if substantially all of its senior management is located in the United States. If this or similar legislation is passed that changes our U.S. tax position, it could have a material adverse effect on our net income, our cash flow and our financial condition.

We may become subject to taxes in Bermuda after March 31, 2035, which may have a material adverse effect on our results of operations.

The Bermuda Minister of Finance, under the Exempted Undertakings Tax Protection Act 1966 of Bermuda, as amended, has given us an assurance that if any legislation is enacted in Bermuda that would impose tax computed on profits or income, or computed on any capital asset, gain or appreciation, or any tax in the nature of estate duty or inheritance tax, then the imposition of any such tax will not be applicable to us or any of our operations, shares, debentures or other obligations until March 31, 2035, except insofar as such tax applies to persons who ordinarily reside in Bermuda or to any taxes payable by us in respect of real property owned or leased by us in Bermuda.

The impact of Bermuda's letter of commitment to the Organization for Economic Cooperation and Development to eliminate harmful tax practices is uncertain and could adversely affect our tax status in Bermuda.

The Organization for Economic Cooperation and Development ("OECD") has published reports and launched a global initiative among member and non member countries on measures to limit harmful tax competition. These measures are largely directed at counteracting the effects of tax havens and preferential tax regimes in countries around the world. According to the OECD, Bermuda is a jurisdiction that has substantially implemented the internationally agreed tax standard and as such is listed on the OECD "white" list. However, we are not able to predict whether any changes will be made to this classification or whether such changes will subject us to additional taxes.

The adoption of financial reform legislation by the United States Congress in 2010, and its implementing regulations, could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price and other risks associated with our business.

We use derivative instruments to manage our commodity price and interest rate risk. The United States Congress adopted comprehensive financial reform legislation in 2010 that establishes federal oversight and regulation of the over the counter derivatives market and entities, such as ours, that participate in that market. The Dodd Frank Act was signed into law by the President on July 21, 2010. The Commodity Futures Trading Commission ("CFTC"), which has jurisdiction over derivatives instruments that are "swaps," has implemented many, but not all, of these provisions through regulations; the SEC, which regulates "security-based swaps" has proposed but not finalized most of its implementing regulations.

Table of Contents

Of particular importance to us, the CFTC has the authority to, under certain findings, establish position limits for certain futures, options on futures and swap contracts. Certain bona fide hedging transactions or positions would be exempt from these position limits. The CFTC has proposed rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain energy, metal, and agricultural physical commodities, subject to exceptions for certain bona fide hedging transactions. It is not possible at this time to predict when the CFTC will finalize these regulations; therefore, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and index credit default swaps for mandatory clearing and exchange trading. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. The application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that the Company uses for hedging.

Derivatives dealers that we transact with will need to comply with new margin and segregation requirements for uncleared swaps and security-based swaps. While it is expected that our uncleared derivatives transactions will not directly be subject to those margin requirements, due to the increased costs to dealers for transacting uncleared derivatives in general, our costs for these transactions may increase.

The Dodd Frank Act and its implementing regulations may also require the counterparties to our derivative instruments to register with the CFTC and become subject to substantial regulation or even spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. These requirements and others could significantly increase the cost of derivatives contracts (including through requirements to clear swaps and to post collateral, each of which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Our revenues could also be adversely affected if a consequence of the legislation and regulations is to lower commodity prices.

The European Union and other non U.S. jurisdictions are also implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we or our transactions may become subject to such regulations. At this time, the impact of such regulations is not clear.

Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

We may become a “passive foreign investment company” for U.S. federal income tax purposes, which could create adverse tax consequences for U.S. investors.

U.S. investors that hold stock in a “passive foreign investment company” (“PFIC”) are subject to special rules that can create adverse U.S. federal income tax consequences, including imputed interest charges and recharacterization of certain gains and distributions. Based on management estimates and projections of future revenue, we do not believe that we will be a PFIC for the current taxable year and we do not expect to become one in the foreseeable future. Because PFIC status is a factual determination that is made annually and thus is subject to change, there can be no assurance that we will not be a PFIC for any taxable year.

A cyber incident could result in information theft, data corruption, operational disruption, and/or financial loss.

The oil and gas industry has become increasingly dependent on digital technologies to conduct day to day operations including certain exploration, development and production activities. For example, software programs are used to interpret seismic data, manage drilling rigs, conduct reservoir modeling and reserves estimation, and to process and record financial and operating data.

We depend on digital technology, including information systems and related infrastructure as well as cloud application and services, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves and for many other activities related to our business. Our business partners, including vendors, service providers, co venturers, purchasers of our production, and financial institutions, are also dependent on digital technology. The complexity of the technologies needed to explore for and develop oil and gas in increasingly difficult physical environments, such as deepwater, and global competition for oil and gas resources make certain information more attractive to thieves.

Table of Contents

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial of service on websites. For example, in 2012, a wave of network attacks impacted Saudi Arabia's oil industry and breached financial institutions in the U.S. A number of U.S. companies have also been subject to cyber-attacks in recent years resulting in unauthorized access to sensitive information. Certain countries are believed to possess cyber warfare capabilities and are credited with attacks on American companies and government agencies.

Our technologies, systems, networks, and those of our business partners may become the target of cyber attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations. Although to date we have not experienced any significant cyber attacks, there can be no assurance that we will not be the target of cyber attacks in the future or suffer such losses related to any cyber incident. As cyber threats 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 information security vulnerabilities.

Outbreaks of disease in the geographies in which we operate may adversely affect our business operations and financial condition.

Many of our operations are currently, and will likely remain in the near future, in developing countries which are susceptible to outbreaks of disease and may lack the resources to effectively contain such an outbreak quickly. Such outbreaks may impact our ability to explore for oil and gas, develop or produce our license areas by limiting access to qualified personnel, increasing costs associated with ensuring the safety and health of our personnel, restricting transportation of personnel, equipment, supplies and oil and gas production to and from our areas of operation and diverting the time, attention and resources of government agencies which are necessary to conduct our operations. In addition, any losses we experience as a result of such outbreaks of disease which impact sales or delay production may not be covered by our insurance policies.

An epidemic of the Ebola virus disease occurred in parts of West Africa in 2014 and continued through 2015. A substantial number of deaths were reported by the World Health Organization ("WHO") in West Africa, and the WHO declared it a global health emergency. It is impossible to predict the effect and potential spread of new outbreaks of the Ebola virus in West Africa and surrounding areas. Should another Ebola virus outbreak occur, including to the countries in which we operate, or not be satisfactorily contained, our exploration, development and production plans for our operations could be delayed, or interrupted after commencement. Any changes to these operations could significantly increase costs of operations. Our operations require contractors and personnel to travel to and from Africa as well as the unhindered transportation of equipment and oil and gas production (in the case of our producing fields). Such operations also rely on infrastructure, contractors and personnel in Africa. If travel bans are implemented or extended to the countries in which we operate, or contractors or personnel refuse to travel there, we could be adversely affected. If services are obtained, costs associated with those services could be significantly higher than planned which could have a material adverse effect on our business, results of operations, and future cash flow. In addition, should an Ebola virus outbreak spread to the countries in which we operate, access to the FPSOs could be restricted and/or terminated. The FPSOs are potentially able to operate for a short period of time without access to the mainland, but if restrictions extended for a longer period we and the operator of the impacted fields would likely be required to cease production and other operations until such restrictions were lifted.

Risks Relating to Our Common Shares

Our share price may be volatile, and purchasers of our common shares could incur substantial losses.

Our share price may be volatile. The stock market in general has experienced extreme volatility that has often been unrelated to the operating performance of particular companies. The market price for our common shares may be influenced by many factors, including, but not limited to:

- the price of oil and natural gas;
- the success of our exploration and development operations, and the marketing of any oil and natural gas we produce;
- operational incidents;

- regulatory developments in Bermuda, the United States and foreign countries where we operate;
- the recruitment or departure of key personnel;
- quarterly or annual variations in our financial results or those of companies that are perceived to be similar to us;
- market conditions in the industries in which we compete and issuance of new or changed securities;
- analysts' reports or recommendations;
- the failure of securities analysts to cover our common shares or changes in financial estimates by analysts;
- the inability to meet the financial estimates of analysts who follow our common shares;
- the issuance or sale of any additional securities of ours;
- investor perception of our company and of the industry in which we compete; and
- general economic, political and market conditions.

A substantial portion of our total issued and outstanding common shares may be sold into the market at any time. This could cause the market price of our common shares to drop significantly, even if our business is doing well.

All of the shares sold in our initial public offering are freely tradable without restrictions or further registration under the federal securities laws, unless purchased by our "affiliates" as that term is defined in Rule 144 under the Securities Act of 1933, as amended (the "Securities Act"). Substantially all of the remaining common shares are restricted securities as defined in Rule 144 under the Securities Act (unless they have been sold pursuant to Rule 144 to date). Restricted securities may be sold in the U.S. public market only if registered or if they qualify for an exemption from registration, including by reason of Rule 144 or Rule 701 under the Securities Act. All of our restricted shares are eligible for sale in the public market, subject in certain circumstances to the volume, manner of sale limitations with respect to shares held by our affiliates and other limitations under Rule 144. Additionally, we have registered all our common shares that we may issue under our employee benefit plans. These shares can be freely sold in the public market upon issuance, unless pursuant to their terms these share awards have transfer restrictions attached to them. Sales of a substantial number of our common shares, or the perception in the market that the holders of a large number of shares intend to sell common shares, could reduce the market price of our common shares.

The concentration of our share capital ownership among our largest shareholders, and their affiliates, will limit your ability to influence corporate matters.

Our two largest shareholders collectively own approximately 37% of our issued and outstanding common shares as of December 31, 2017. Consequently, these shareholders have significant influence over all matters that require approval by our shareholders, including the election of directors and approval of significant corporate transactions. This concentration of ownership will limit your ability to influence corporate matters, and as a result, actions may be taken that you may not view as beneficial.

Holders of our common shares will be diluted if additional shares are issued.

We may issue additional common shares, preferred shares, warrants, rights, units and debt securities for general corporate purposes, including, but not limited to, repayment or refinancing of borrowings, working capital, capital expenditures, investments and acquisitions. We continue to actively seek to expand our business through complementary or strategic acquisitions, and we may issue additional common shares in connection with those acquisitions. We also issue restricted shares to our executive officers, employees and independent directors as part of their compensation. If we issue additional common shares in the future, it may have a dilutive effect on our current outstanding shareholders.

We do not intend to pay dividends on our common shares and, consequently, your only opportunity to achieve a return on your investment is if the price of our shares appreciates.

We do not plan to declare dividends on shares of our common shares in the foreseeable future. Additionally, certain of our subsidiaries are currently restricted in their ability to pay dividends to us pursuant to the terms of our commercial debt facility unless they meet certain conditions, financial and otherwise. Consequently, investors must rely on sales of their common shares after price appreciation, which may never occur, as the only way to realize a return on their investment.

Table of Contents

We are a Bermuda company and a significant portion of our assets are located outside the United States. As a result, it may be difficult for shareholders to enforce civil liability provisions of the federal or state securities laws of the United States.

We are a Bermuda exempted company. As a result, the rights of holders of our common shares will be governed by Bermuda law and our memorandum of association and bye laws. The rights of shareholders under Bermuda law may differ from the rights of shareholders of companies incorporated in other jurisdictions. Some of our directors are not residents of the United States, and a substantial portion of our assets are located outside the United States. As a result, it may be difficult for investors to effect service of process on that person in the United States or to enforce in the United States judgments obtained in U.S. courts against us or that person based on the civil liability provisions of the U.S. securities laws. It is doubtful whether courts in Bermuda will enforce judgments obtained in other jurisdictions, including the United States, against us or our directors or officers under the securities laws of those jurisdictions or entertain actions in Bermuda against us or our directors or officers under the securities laws of other jurisdictions.

Bermuda law differs from the laws in effect in the United States and might afford less protection to shareholders.

Our shareholders could have more difficulty protecting their interests than would shareholders of a corporation incorporated in a jurisdiction of the United States. As a Bermuda company, we are governed by the Companies Act 1981 of Bermuda (the "Bermuda Companies Act"). The Bermuda Companies Act differs in some material respects from laws generally applicable to U.S. corporations and shareholders, including the provisions relating to interested directors, mergers and acquisitions, takeovers, shareholder lawsuits and indemnification of directors. Set forth below is a summary of these provisions, as well as modifications adopted pursuant to our bye laws, which differ in certain respects from provisions of Delaware corporate law. Because the following statements are summaries, they do not discuss all aspects of Bermuda law that may be relevant to us and our shareholders.

Interested Directors. Under Bermuda law and our bye laws, as long as a director discloses a direct or indirect interest in any contract or arrangement with us as required by law, such director is entitled to vote in respect of any such contract or arrangement in which he or she is interested, unless disqualified from doing so by the chairman of the meeting, and such a contract or arrangement will not be voidable solely as a result of the interested director's participation in its approval. In addition, the director will not be liable to us for any profit realized from the transaction. In contrast, under Delaware law, such a contract or arrangement is voidable unless it is approved by a majority of disinterested directors or by a vote of shareholders, in each case if the material facts as to the interested director's relationship or interests are disclosed or are known to the disinterested directors or shareholders, or such contract or arrangement is fair to the corporation as of the time it is approved or ratified. Additionally, such interested director could be held liable for a transaction in which such director derived an improper personal benefit.

Mergers and Similar Arrangements. The amalgamation of a Bermuda company with another company or corporation (other than certain affiliated companies) requires the amalgamation agreement to be approved by the company's board of directors and by its shareholders. Unless the company's bye laws provide otherwise, the approval of 75% of the shareholders voting at such meeting is required to approve the amalgamation agreement, and the quorum for such meeting must be two persons holding or representing more than one third of the issued shares of the company. Our bye laws provide that an amalgamation (other than with a wholly owned subsidiary, per the Bermuda Companies Act) that has been approved by the board must only be approved by shareholders owning a majority of the issued and outstanding shares entitled to vote. Under Bermuda law, in the event of an amalgamation of a Bermuda company with another company or corporation, a shareholder of the Bermuda company who is not satisfied that fair value has been offered for such shareholder's shares may, within one month of notice of the shareholders meeting, apply to the Supreme Court of Bermuda to appraise the fair value of those shares. Under Delaware law, with certain exceptions, a merger, consolidation or sale of all or substantially all the assets of a corporation must be approved by the board of directors and a majority of the issued and outstanding shares entitled to vote thereon. Under Delaware law, a shareholder of a corporation participating in certain major corporate transactions may, under certain circumstances, be entitled to appraisal rights pursuant to which such shareholder may receive cash in the amount of the fair value of the shares held by such shareholder (as determined by a court) in lieu of the consideration such shareholder would otherwise receive in the transaction.

Shareholders’ Suit. Class actions and derivative actions are generally not available to shareholders under Bermuda law. The Bermuda courts, however, would ordinarily be expected to permit a shareholder to commence an action in the name of a company to remedy a wrong to the company where the act complained of is alleged to be beyond the corporate power of the company or illegal, or would result in the violation of the company’s memorandum of association or bye laws. Furthermore, consideration would be given by a Bermuda court to acts that are alleged to constitute a fraud against the minority shareholders or where an act requires the approval of a greater percentage of the company’s shareholders than that which actually approved it.

When the affairs of a company are being conducted in a manner which is oppressive or prejudicial to the interests of some part of the shareholders, one or more shareholders may apply to the Supreme Court of Bermuda, which may make such order

Table of Contents

as it sees fit, including an order regulating the conduct of the company's affairs in the future or ordering the purchase of the shares of any shareholders by other shareholders or by the company.

Our bye laws contain a provision by virtue of which we and our shareholders waive any claim or right of action that they have, both individually and on our behalf, against any director or officer in relation to any action or failure to take action by such director or officer, except in respect of any fraud or dishonesty of such director or officer. Class actions and derivative actions generally are available to shareholders under Delaware law for, among other things, breach of fiduciary duty, corporate waste and actions not taken in accordance with applicable law. In such actions, the court has discretion to permit the winning party to recover attorneys' fees incurred in connection with such action.

Indemnification of Directors and Officers. We may indemnify our directors and officers in their capacity as directors or officers for any loss arising or liability attaching to them by virtue of any rule of law in respect of any negligence, default, breach of duty or breach of trust of which a director or officer may be guilty in relation to the company other than in respect of his own fraud or dishonesty. Under Delaware law, a corporation may indemnify a director or officer of the corporation against expenses (including attorneys' fees), judgments, fines and amounts paid in settlement actually and reasonably incurred in defense of an action, suit or proceeding by reason of such position if such director or officer acted in good faith and in a manner he or she reasonably believed to be in or not opposed to the best interests of the corporation and, with respect to any criminal action or proceeding, such director or officer had no reasonable cause to believe his or her conduct was unlawful. In addition, we have entered into customary indemnification agreements with our directors.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

See "Item 1. Business." We also have various operating leases for rental of office space, office and field equipment, and vehicles. See Note 15 of Notes to the Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for the future minimum rental payments. Such information is incorporated herein by reference.

Item 3. Legal Proceedings

From time to time, we may be involved in various legal and regulatory proceedings arising in the normal course of business. While we cannot predict the occurrence or outcome of these proceedings with certainty, we do not believe that an adverse result in any pending legal or regulatory proceeding, individually or in the aggregate, would be material to our consolidated financial condition or cash flows; however, an unfavorable outcome could have a material adverse effect on our results of operations for a specific interim period or year.

In June 2016, Kosmos Energy Ghana HC filed a Request for Arbitration with the International Chamber of Commerce against Tullow Ghana Limited in connection with a dispute arising under the DT Joint Operating Agreement. At dispute is Kosmos Energy Ghana HC's responsibility for expenditures arising from Tullow Ghana Limited's contract with Seadrill for use of the West Leo drilling rig once partner-approved 2016 work program objectives were concluded. Tullow has charged such expenditures to the DT joint account. Kosmos disputes that these expenditures are chargeable to the DT joint account on the basis that the Seadrill West Leo drilling rig contract was not approved by the DT operating committee pursuant to the DT Joint Operating Agreement.

Item 4. Mine Safety Disclosures

Not applicable.

Table of Contents

PART II

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

Common Shares Trading Summary

Our common shares are traded on the NYSE and LSE under the symbol KOS. The following table shows the quarterly high and low sale prices of our common shares based on the NYSE.

	2017		2016	
	High	Low	High	Low
First Quarter	$7.39	$5.53	$6.41	$3.17
Second Quarter	7.90	5.65	6.79	4.63
Third Quarter	8.21	5.99	6.63	5.16
Fourth Quarter	8.62	6.55	7.14	4.39

As of February 21, 2018, based on information from the Company's transfer agent, Computershare Trust Company, N.A., the number of holders of record of Kosmos' common shares was 68. On February 21, 2018, the last reported sale price of Kosmos' common shares, as reported on the NYSE, was $5.60 per share.

We have never paid any dividends on our common shares. At the present time, we intend to retain all of our future earnings, if any, generated by our operations for the development and growth of our business. Additionally, we are subject to Bermuda legal constraints that may affect our ability to pay dividends on our common shares and make other payments. Under the Bermuda Companies Act, we may not declare or pay a dividend if there are reasonable grounds for believing that we are, or would after the payment be, unable to pay our liabilities as they become due or that the realizable value of our assets would thereafter be less than the aggregate of our liabilities, issued share capital and share premium accounts. Certain of our subsidiaries are also currently restricted in their ability to pay dividends to us pursuant to the terms of the Senior Notes, the Facility and the Corporate Revolver unless we meet certain conditions, financial and otherwise. Any decision to pay dividends in the future is at the discretion of our board of directors and depends on our financial condition, results of operations, capital requirements and other factors that our board of directors deems relevant. Currently we do not anticipate paying any dividends in the foreseeable future.

Issuer Purchases of Equity Securities

Under the terms of our Long Term Incentive Plan ("LTIP"), we have issued restricted shares to our employees. On the date that these restricted shares vest, we provide such employees the option to sell shares to cover their tax liability, via a net exercise provision pursuant to our applicable restricted share award agreements and the LTIP, at either the number of vested shares (based on the closing price of our common shares on such vesting date) equal to the minimum statutory tax liability owed by such grantee or up to the maximum statutory tax liability for such grantee. The Company may repurchase the restricted shares sold by the grantees to settle their tax liability. The repurchased shares are reallocated to the number of shares available for issuance under the LTIP. The following table outlines the total number of shares purchased during fiscal year 2017 and the average price paid per share.

Table of Contents

	Total Number of Shares Purchased (In thousands)	Average Price Paid per Share
January 1, 2017—January 31, 2017	74	$ 7.01
February 1, 2017—February 29, 2017	—	—
March 1, 2017—March 31, 2017	—	—
April 1, 2017—April 30, 2017	—	—
May 1, 2017—May 31, 2017	—	—
June 1, 2017—June 30, 2017	13	6.12
July 1, 2017—July 31, 2017	—	—
August 1, 2017—August 31, 2017	—	—
September 1, 2017—September 30, 2017	—	—
October 1, 2017—October 31, 2017	—	—
November 1, 2017—November 30, 2017	—	—
December 1, 2017—December 31, 2017	—	—
Total	87	6.87

Share Performance Graph

The following Performance Graph and related information shall not be deemed “soliciting material” or to be “filed” with the SEC, nor shall such information be incorporated by reference into any future filings under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filings.

The following graph illustrates changes over the five-year period ended December 31, 2017, in cumulative total stockholder return on our common shares as measured against the cumulative total return of the S&P 500 Index and the Dow Jones U.S. Exploration & Production Index. The graph tracks the performance of a $100 investment in our common shares and in each index (with the reinvestment of all dividends).

	December 31,					
	2012	2013	2014	2015	2016	2017
Kosmos Energy Ltd. (KOS)	$100.00	$90.53	$67.94	$42.11	$56.76	$55.47
S&P 500 (SPX)	100.00	132.37	150.48	152.55	170.78	208.05
Dow Jones U.S. Exploration & Production Index (DWCEXP)	100.00	131.17	114.81	87.02	109.40	109.70

Table of Contents

Item 6. Selected Financial Data

The following selected consolidated financial information set forth below as of and for the five years ended, December 31, 2017, should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data."

Consolidated Statements of Operations Information:

	Years Ended December 31,				
	2017	2016	2015	2014	2013
	(In thousands, except per share data)				
Revenues and other income:					
Oil and gas revenue	$578,139	$310,377	$446,696	$855,877	$851,212
Gain on sale of assets	—	—	24,651	23,769	—
Other income, net	58,697	74,978	209	3,092	941
Total revenues and other income	636,836	385,355	471,556	882,738	852,153
Costs and expenses:					
Oil and gas production	126,850	119,367	105,336	100,122	96,791
Facilities insurance modifications, net	(820)	14,961	—	—	—
Exploration expenses	216,050	202,280	156,203	93,519	230,314
General and administrative	68,302	87,623	136,809	135,231	158,421
Depletion and depreciation	255,203	140,404	155,966	198,080	222,544
Interest and other financing costs, net	77,595	44,147	37,209	45,548	47,590
Derivatives, net	59,968	48,021	(210,649)	(281,853)	17,027
Restructuring charges	—	—	—	11,742	—
Loss on equity method investment	6,252	—	—	—	—
Other expenses, net	5,291	23,116	5,246	2,081	3,512
Total costs and expenses	814,691	679,919	386,120	304,470	776,199
Income (loss) before income taxes	(177,855)	(294,564)	85,436	578,268	75,954
Income tax expense (benefit)	44,937	(10,784)	155,272	298,898	166,998
Net income (loss)	$(222,792)	$(283,780)	$(69,836)	$279,370	$(91,044)
Net income (loss) per share:					
Basic	$(0.57)	$(0.74)	$(0.18)	$0.73	$(0.24)
Diluted	$(0.57)	$(0.74)	$(0.18)	$0.72	$(0.24)
Weighted average number of shares used to compute net income (loss) per share:					
Basic	388,375	385,402	382,610	379,195	376,819
Diluted	388,375	385,402	382,610	386,119	376,819

Table of Contents

Consolidated Balance Sheets Information:

	December 31,				
	2017	2016	2015(1)(2)	2014(1)	2013(1)
	(In thousands)				
Cash and cash equivalents	$233,412	$194,057	$275,004	$554,831	$598,108
Total current assets	533,602	475,187	734,148	1,010,476	734,961
Total property and equipment, net	2,317,828	2,708,892	2,322,839	1,784,846	1,522,962
Total other assets	341,173	157,386	146,063	131,537	53,742
Total assets	3,192,603	3,341,465	3,203,050	2,926,859	2,311,665
Total current liabilities	428,730	370,025	456,741	448,771	219,324
Total long-term liabilities	1,866,761	1,890,241	1,420,796	1,139,129	1,100,006
Total shareholders' equity	897,112	1,081,199	1,325,513	1,338,959	992,335
Total liabilities and shareholders' equity	3,192,603	3,341,465	3,203,050	2,926,859	2,311,665

---

(1) Effective December 31, 2015, the Company adopted new guidance on the presentation of debt issuance costs. This guidance was adopted retrospectively and all prior periods have been adjusted to reflect this change in accounting principle.

(2) Effective December 31, 2015, the Company adopted new guidance on the presentation of deferred taxes. The Company elected to adopt the accounting change using the prospective method. See Note 2 of Notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows Information:

	December 31,				
	2017	2016	2015(1)	2014(1)	2013(1)
	(In thousands)				
Net cash provided by (used in):					
Operating activities	$236,617	$52,077	$440,779	$443,586	$522,404
Investing activities	(152,565)	(537,763)	(796,433)	(368,603)	(322,383)
Financing activities	(52,261)	448,019	79,634	(139,184)	(115,327)

---

(1) Effective December 31, 2016, the Company adopted new guidance on the presentation of restricted cash. This guidance was adopted retrospectively and all prior periods have been adjusted to reflect this change in accounting principle.

Table of Contents

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

The following discussion and analysis contains forward looking statements that involve risks and uncertainties. Our actual results may differ materially from those discussed in the forward looking statements as a result of various factors, including, without limitation, those set forth in “Cautionary Statement Regarding Forward Looking Statements” and “Item 1A. Risk Factors.” The following discussion of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and the notes thereto included elsewhere in this annual report on Form 10 K.

Overview

Kosmos is a leading independent oil and gas exploration and production company focused on frontier and emerging areas along the Atlantic Margins. Our assets include existing production and development projects offshore Ghana and Equatorial Guinea, large discoveries and significant further exploration potential offshore Mauritania and Senegal, as well as exploration licenses offshore Cote d'Ivoire, Equatorial Guinea, Morocco, Sao Tome and Principe, and Suriname.

Recent Developments

Corporate

In February 2018, the Company amended and restated the Facility with a total commitment of $1.5 billion from a number of financial institutions with additional commitments up to $0.5 billion being available if the existing financial institutions increase their commitments or if commitments from new financial institutions are added. As a result of the financing, we will record a $5.7 million loss on the extinguishment of debt in the first quarter of 2018.
See “—Liquidity and Capital Resources” for additional information regarding the Facility.

Our revolving letter of credit facility agreement ("LC Facility") has flexibility that allows us to increase or decrease the available amount as needed if the existing lender increases its commitment or if commitments from new financial institutions are added. During the first quarter of 2017, the LC Facility size was increased to $115.0 million and in April 2017, we reduced the size of our LC Facility to $70 million. In February 2018, the LC Facility was increased to $73 million to facilitate the issuance of additional letters of credit.

In August 2017, we announced that our entire issued and outstanding share capital has been admitted to the standard listing segment of the Official List of the Financial Conduct Authority and to trading on the London Stock Exchange’s ("LSE") main market for listed securities under the ticker “KOS”. The listing is expected to broaden Kosmos’ international investor base and provide access to an additional pool of capital.

On December 22, 2017, the President of the United States signed P.L. 115-97, the Tax Cut and Jobs Act (the Tax Reform Act), into law. Many of the provisions of the Act are effective beginning January 1, 2018, most notable of which is the reduction in the U.S. corporate income tax rate from 35% to 21%. We are required to adjust our U.S. net deferred tax assets for the effect of changes in tax laws or tax rates during the period that includes the date of enactment. Accordingly, we have recorded a $16.7 million charge to deferred tax expense in December 2017 as a result of reducing our net deferred tax assets. The changes required by the Tax Reform Act will have a positive, though immaterial impact, on our effective tax rate.

Rig Agreement

In January 2017, Kosmos Energy Ventures (“KEV”), a subsidiary of Kosmos Energy Ltd., exercised its right under the amended Atwood Achiever rig agreement with Atwood Oceanics, Inc. to exercise its option to cancel the fourth year of the agreement and revert to the original day rate of approximately $0.6 million per day and original agreement end date of November 2017. KEV made a rate recovery payment of approximately $48.1 million based on this election. In November 2017, we entered into a drilling rig contract for the ENSCO DS-12 which includes one firm well plus six well options. We have completed the initial well and have exercised one of the six well options which will be drilled in 2018.

Kosmos-BP Strategic Exploration Alliance

During the second quarter of 2017, we formed the Kosmos-BP Strategic Exploration Alliance ("Alliance"). This Alliance broadens the relationship that previously covered new venture opportunities in Mauritania, Senegal and The Gambia to create an Atlantic Margin explorer-developer partnership. The Alliance will leverage our regional exploration knowledge and capability together with BP's deepwater development expertise to execute a selective, joint frontier and emerging basin exploration strategy in the Atlantic Margin.

Table of Contents

Cote d'Ivoire

In December 2017, as part of our Alliance with BP, we entered into petroleum contracts covering Blocks CI-526, CI-602, CI-603, CI-707 and CI-708 with the Government of Cote d'Ivoire. We have a 45% participating interest and are the operator in all five blocks. BP has a 45% participating interest in the blocks and the Cote d'Ivoire national oil company, PETROCI Holding ("PETROCI"), currently has a 10% carried interest. The petroleum contracts cover approximately 17,000 square kilometers, with a first exploration period of three years. The first exploration period work program includes a 12,000 square kilometer 3D seismic acquisition across the five blocks.

Strategic entry into Equatorial Guinea

Ceiba Field and Okume Complex Acquisition

In the fourth quarter of 2017, through a joint venture with an affiliate of Trident, we acquired all of the equity interest of Hess International Petroleum Inc., a subsidiary of Hess, which holds an 85% paying interest (80.75% revenue interest) in the Ceiba Field and Okume Complex assets. Under the terms of the agreement, Kosmos and Trident each own 50% of Hess International Petroleum Inc. Hess International Petroleum Inc. was subsequently renamed Kosmos-Trident International Petroleum Inc. ("KTIPI"). Kosmos is primarily responsible for exploration and subsurface evaluation while Trident is primarily responsible for production operations and optimization. The transaction expands our position in the Gulf of Guinea and provides immediate cash flow through existing production with potential to increase existing production and also provides step-out exploration opportunities with potential low cost tie-back through existing infrastructure. The gross acquisition price is $650 million effective as of January 1, 2017. After post closing entries Kosmos paid net cash of approximately $231 million, with a combination of cash on hand and availability under the Facility. The transaction is accounted for as an equity method investment.

Exploration Blocks

In October 2017, we also entered into petroleum contracts covering Blocks EG-21, S, and W with the Republic of Equatorial Guinea. Ratification of the petroleum contracts by the President of Equatorial Guinea is expected in early 2018. We presently have an 80% participating interest and are the operator in all three blocks, but pursuant to an agreement with Trident, we expect to assign a 40% participating interest in the blocks to an affiliate of Trident after ratification. The Equatorial Guinean national oil company, Guinea Equatorial De Petroleos ("GEPetrol"), currently has a 20% carried participating interest during the exploration period. Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest. The petroleum contracts cover approximately 6,000 square kilometers, with a first exploration period of five years from the date of notification of ratification by the President of Equatorial Guinea. The first exploration period consists of two sub-periods of three and two years, respectively. The first exploration sub-period work program includes an approximately 6,000 square kilometer 3D seismic acquisition requirement across the blocks.

Ghana

Jubilee

Kosmos and its partners have determined the preferred long-term solution to the turret bearing issue is to convert the FPSO to a permanently spread moored facility. The Jubilee turret remediation work is progressing as planned and the FPSO spread-mooring at its current heading was completed in February 2017. This allowed the tug boats previously required to hold the vessel on a fixed heading to be removed, significantly reducing the cost and complexity of the current operation. The next phase of the remediation work involves lifting and locking the main bearing. With regard to the turret remediation plan, the partnership is aligned on the engineering solution. This involves a shutdown to stabilize the turret bearing during the first quarter of 2018 followed by work to rotate the vessel to a new heading and permanently spread moor the vessel. The turret stabilization shutdown is being conducted in two phases, the first of which is complete and oil production is back online. The second phase is expected to commence around the end of the first quarter of 2018, and we anticipate the overall shutdown of oil production for both phases to be around four weeks. It is anticipated the gas system will be shut-in for slightly longer to complete non-turret related maintenance. We now expect the rotation of the vessel to take place around the end of 2018 with minimal impact to production in 2018.

The financial impact of lower Jubilee production as well as the additional expenditures associated with the damage to the turret bearing is mitigated through a combination of the comprehensive Hull and Machinery insurance ("H&M"), procured by the operator, Tullow, on behalf of the Jubilee Unit partners, and the corporate Loss of Production Income ("LOPI") insurance procured by Kosmos. Our LOPI coverage for this incident ended in May 2017 and final claim amounts have been approved and cash proceeds were received in August 2017.

The Greater Jubilee Full Field Development Plan ("GJFFDP") was resubmitted to the government of Ghana in September 2017 and subsequently approved in October 2017. This plan, which is expected to increase proved reserves and extend the field production profile, has been optimized to reduce overall capital expenditures to reflect the current oil price market. In

Table of Contents

November 2015, we signed the Jubilee Field Unit Expansion Agreement with our partners, which became effective upon approval of the GJFFDP, to allow for the development of the Mahogany and Teak discoveries through the Jubilee FPSO and infrastructure, thus reducing their development cost. Upon approval of the GJFFDP by the Ministry of Energy in October 2017, operatorship for the Mahogany and Teak discoveries transferred to Tullow. Kosmos continues to assist Tullow with the transition process, which is expected to extend into the first half of 2018.

Tweneboa, Enyenra and Ntomme (“TEN”)

In September 2017, the Special Chamber of the International Tribunal of the Sea (ITLOS) issued its final decision in the maritime boundary dispute between the Governments of Ghana and Cote d'Ivoire. The maritime boundary delimited by the Special Chamber's decision has no impact on TEN production or reserves or otherwise on the company's interests in Ghana. Production from TEN in the year ended December 31, 2017 averaged approximately 55,800 bopd which exceeded the operator’s 2017 guidance of 50,000 bopd. We expect to resume drilling in early 2018 and production is expected to increase towards FPSO capacity.

Mauritania and Senegal Partnership with BP

In December 2016, we announced a partnership with affiliates of BP p.l.c. (‘‘BP’’) in Mauritania and Senegal following a competitive farm-out process for our interests in our blocks offshore Mauritania and Senegal. We believe BP is the optimal partner to advance the gas developments in these blocks. In Mauritania, BP acquired a 62% participating interest in our four Mauritania licenses (C6, C8, C12 and C13). In Senegal, BP acquired a 49.99% interest in Kosmos BP Senegal Limited ("KBSL"), our controlled affiliate company which held a 65% participating interest in the Cayar Offshore Profond and the Saint Louis Offshore Profond blocks offshore Senegal. The participating interest gave effect to the completion of our exercise in December 2016 of an option to increase our equity in each contract area from 60% to 65% in exchange for carrying Timis Corporation’s paying interest share of a third well in either contract area, subject to a maximum gross cost of $120.0 million. In October 2017, upon approval, KBSL transferred a 30% working interest in the Senegal Blocks to BP Senegal Investments Limited in exchange for their outstanding shares of KBSL. After the transfer, KBSL has a 30% direct participating interest in the Senegal Blocks and therefore, KBSL will no longer be accounted for under the equity method of accounting. In consideration for these transactions, Kosmos received $162 million in cash up front, a $221 million exploration and appraisal carry, and will receive up to $533 million in a development carry and variable consideration up to $2 per barrel for up to 1 billion barrels of liquids, structured as a production royalty, subject to future liquids discovery and prevailing oil prices. Upon completion of the unwind, the cap on exploration and appraisal carry was increased by $7 million.

Greater Tortue Discovery

In August 2017, we announced the successful completion of the drill stem test ("DST") of the Tortue-1 well, demonstrating that the Tortue field is a world-class resource and confirming key development parameters including well deliverability, reservoir connectivity, and fluid composition. The Tortue-1 well flowed at a sustained, equipment-constrained rate of approximately 60 million cubic feet per day (MMcfd) during the main extended flow period, with minimal pressure drawdown, providing confidence in well designs that are each capable of producing approximately 200 MMcfd. The DST results confirmed a connected volume per well consistent with the current development scheme, which together with the high well rate is expected to result in a low number of development wells compared to equivalent schemes. Initial analysis of fluid samples collected during the test indicate Tortue gas is well suited for liquefaction given low levels of liquids and minimal impurities. Data acquired from the DST will be used to further optimize field development and to refine process design parameters critical to the front end engineering and design ("FEED") process.

In February 2018, the governments of Mauritania and Senegal signed an Inter-Governmental Cooperation Agreement ("ICA") which enables the development of the cross-border Tortue natural gas field to continue moving forward. With this agreement in place, we expect a final investment decision for the Greater Tortue project around the end of 2018 and are aiming for first gas in late 2021.

Mauritania

In March 2017, we completed a multi-block 3D seismic survey offshore Mauritania covering approximately 11,700 square kilometers over Blocks C6, C8, C12 and C13.

In September 2017, we closed a farm-in agreement with Tullow Mauritania Limited, a subsidiary of Tullow Oil plc ("Tullow"), to acquire a 15% non-operated participating interest in Block C18 offshore Mauritania. Based on the terms of the agreement, we will reimburse a portion of past and interim period costs and partially carry Tullow's share of a planned 3D seismic program (up to $2.1 million net to Kosmos). We will also pay Tullow $2.5 million by the end of the initial phase of the exploration period for additional carry of seismic and other joint account costs.

Table of Contents

Drilling of the Hippocampe-1 exploration well on the C8 block was completed in October 2017. Designed to test Lower Cenomanian and Albian reservoirs, the well was drilled to a total depth of approximately 5,500 meters. The well has been plugged and abandoned. Total well and other related costs of $31.3 million are included in exploration expenses in the accompanying consolidated statement of operations for the year ended December 31, 2017.

In December 2017, the Lamantin-1 exploration well was drilled to a total depth of 5,150 meters. This well was designed to evaluate a previously untested Lower Campanian base of slope fan supplied from the Nouakchott River system, trapped in a combination structural-stratigraphic feature, and charged from underlying, oil-prone Cenomanian/Turonian and Albian source rocks. The well has been plugged and abandoned. Total well and other related costs of $8.0 million are included in exploration expenses in the accompanying consolidated statement of operations for the year ended December 31, 2017.

In December 2017, we began a 3D seismic survey of approximately 9,400 square kilometers over Block C18 offshore Mauritania.

Senegal

In May 2017, we announced the Yakaar-1 exploration well, located in the Cayar Offshore Profond block offshore Senegal, made a major gas discovery. Located approximately 60 miles northwest of Dakar in approximately 2,600 meters of water, the Yakaar-1 exploration well was drilled to a total depth of approximately 4,900 meters. The well intersected a gross hydrocarbon column of 120 meters (394 feet) in three pools within the primary Lower Cenomanian objective and encountered 45 meters (148 feet) of net pay. An appraisal program over the combined Yakaar and Teranaga discoveries is progressing.

In the second quarter of 2017, upon completion of an agreement between BP and Timis Corporation Limited (“Timis”) by which BP acquired Timis’ entire 30% participating interest in the Senegal Blocks, Kosmos agreed to withdraw the exercise of our call option to increase our equity in each of the Cayar Offshore Profond and the Saint Louis Offshore Profond blocks from 60% to 65% in exchange for carrying Timis Corporation’s paying interest share of a third well in either contract area, subject to a maximum gross cost of $120.0 million.

In February 2018, the Requin Tigre-1 exploration well was drilled to a total depth of 5,200 meters and was designed to evaluate Cenomanian and Albian reservoirs in a structural-stratigraphic trap, charged from an underlying Neocomian-Valanginian source kitchen. The prospect was fully tested but did not encounter hydrocarbons. Post-well analysis is currently ongoing to determine the reasons it was unsuccessful. The well has been plugged and abandoned. Total well and other related costs of $0.4 million are included in exploration expenses in the accompanying consolidated statement of operations for the year ended December 31, 2017.

Morocco (including Western Sahara)

In November 2017, Kosmos provided to our co-venturers a notice of withdrawal from Boujdour Maritime and transferred its participating interest and operatorship to ONHYM. Certain transition services are being provided to ONHYM as part of the handover of operatorship. In order to complete our obligations under the petroleum contract, we will continue to fund the remainder of the current seismic program.

In June 2017, we completed a 3D seismic survey of approximately 3,000 square kilometers over the Essaouira Offshore block in the Agadir Basin. Additional geological studies are expected to be conducted beginning in the first quarter of 2018. The current phase of the Essaouira Offshore petroleum contract expires in November 2018.

Suriname

In January 2017, we completed a 3D seismic survey of approximately 6,500 square kilometers over Block 42 and Block 45 offshore Suriname. We plan to drill two exploration wells during 2018.

Sao Tome and Principe

In August 2017, we completed a 3D seismic survey of approximately 15,800 square kilometers over Blocks 5, 6, 11 and 12 offshore Sao Tome and Principe.

In November 2017, we received approval for a one-year extension of Phase 1 for Block 11 offshore Sao Tome and Principe, which now expires in July 2019.

In January 2018, we and our partner BP were awarded the rights to negotiate petroleum contracts for Blocks 10 and 13 offshore Sao Tome and Principe.

Table of Contents

Portugal

In January 2017, we provided to our co-venturers a notice of withdrawal from the Ameijoa, Camarao, Mexilhao and Ostra Blocks offshore Portugal.

Results of Operations

All of our results, as presented in the table below, represent operations from the Jubilee and TEN fields in Ghana and our equity method investment offshore Equatorial Guinea. Certain operating results and statistics for the years ended December 31, 2017, 2016 and 2015 are included in the following tables:

	Year Ended December 31, 2017		
	Kosmos	Equity Method Investment-Equatorial Guinea(1)	Total
	(In thousands, except per barrel data)		
Sales volumes:			
Jubilee	7,782	—	7,782
TEN	2,979	—	2,979
Ceiba / Okume	—	405	405
	10,761	405	11,166
Revenues:			
Oil sales	$578,139	$ 27,307	$605,446
Average sales price per Bbl	53.73	67.42	54.22
Costs:			
Oil production, excluding workovers	$121,429	$ 7,755	$129,184
Oil production, workovers	5,421	—	5,421
Total oil production costs	$126,850	$ 7,755	$134,605
Depletion and depreciation	$255,203	$ 11,181	$266,384
Average cost per Bbl:			
Oil production, excluding workovers	$11.28	$ 19.15	$11.57
Oil production, workovers	0.50	—	0.48
Total oil production costs	11.78	19.15	12.05
Depletion and depreciation	23.72	27.61	23.86
Oil production cost and depletion costs	$35.50	$ 46.76	$35.91

(1) For the year ended December 31, 2017, we have presented our 50% share of the results of operations from the date of acquisition, November 28, 2017 through December 31, 2017. Under the equity method of accounting, we only recognize our share of the net income of KTIPI, which is recorded in loss on equity method investments, net in the consolidated statement of operations.

Table of Contents

	Years Ended December 31, 2016	2015
Sales volumes:		
Jubilee	5,760	8,538
TEN	996	—
	6,756	8,538
Revenues:		
Oil sales	$310,377	$446,696
Average sales price per Bbl	45.94	52.32
Costs:		
Oil production, excluding workovers	$119,758	$92,994
Oil production, workovers	(391)	12,342
Total oil production costs	$119,367	$105,336
Depletion and depreciation	$140,404	$155,966
Average cost per Bbl:		
Oil production, excluding workovers	$17.73	$10.89
Oil production, workovers	(0.06)	1.45
Total oil production costs	17.67	12.34
Depletion and depreciation	20.78	18.27
Oil production cost and depletion costs	$38.45	$30.61

Table of Contents

The discussion of the results of operations and the period to period comparisons presented below analyze our historical results. The following discussion may not be indicative of future results.

Year Ended December 31, 2017 vs. 2016

	Years Ended December 31,		Increase
	2017	2016	(Decrease)
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	$578,139	$310,377	$267,762
Gain on sale of assets	—	—	—
Other income, net	58,697	74,978	(16,281)
Total revenues and other income	636,836	385,355	251,481
Costs and expenses:			
Oil and gas production	126,850	119,367	7,483
Facilities insurance modifications, net	(820)	14,961	(15,781)
Exploration expenses	216,050	202,280	13,770
General and administrative	68,302	87,623	(19,321)
Depletion and depreciation	255,203	140,404	114,799
Interest and other financing costs, net	77,595	44,147	33,448
Derivatives, net	59,968	48,021	11,947
Loss on equity method investments, net	6,252	—	6,252
Other expenses, net	5,291	23,116	(17,825)
Total costs and expenses	814,691	679,919	134,772
Loss before income taxes	(177,855)	(294,564)	116,709
Income tax expense (benefit)	44,937	(10,784)	55,721
Net loss	$(222,792)	$(283,780)	$60,988

The results of operations for our equity method investments are presented in "Loss on equity method investments, net." See “Item 8. Financial Statements and Supplementary Data—Note 7—Equity Method Investments" for additional information regarding our equity method investments.

Oil and gas revenue. Oil and gas revenue increased by $267.8 million as a result of eleven cargos sold during the year ended December 31, 2017 as compared to seven cargos during the year ended December 31, 2016, and as a result of a higher realized price per barrel in 2017. We lifted and sold 10,761 MBbl at an average realized price per barrel of $53.73 in 2017 and 6,756 MBbl at an average realized price per barrel of $45.94 in 2016.

Other income. Other income, net decreased by $16.3 million as we recognized $58.7 million of LOPI proceeds, net during the year ended December 31, 2017 related to the turret bearing issue on the Jubilee FPSO compared to $74.8 million of LOPI proceeds in the previous year. The LOPI claim was finalized in June 2017.

Oil and gas production. Oil and gas production costs increased by $7.5 million during the year ended December 31, 2017 as compared to the year ended December 31, 2016 as a result of lower LOPI claim insurance proceeds recognized during the year ended December 31, 2017 partially offset by accrual adjustments from the Jubilee and TEN fields operator. The LOPI claim was finalized in June 2017.

Facilities insurance modifications, net. During the year ended December 31, 2017, we incurred $19.7 million of facilities insurance modification costs associated with the long-term solution to the turret bearing issue. These costs were offset by $20.5 million of hull and machinery insurance proceeds received during the year ended December 31, 2017 resulting in a credit of $0.8 million. During the year ended December 31, 2016, we incurred $15.0 million of facilities insurance modifications costs associated with the long-term solution to the turret bearing issue with no insurance recoveries.

Table of Contents

Exploration expenses. Exploration expenses increased by $13.8 million during the year ended December 31, 2017, as compared to the year ended December 31, 2016. The increase is primarily a result of higher geological and geophysical costs plus unsuccessful well costs of $43.2 million partially offset by $14.5 million of lower seismic costs and $19.0 million of lower rig related costs incurred during the year ended December 31, 2017 as compared with the year ended December 31, 2016.

General and administrative. General and administrative costs decreased by $19.3 million during the year ended December 31, 2017, as compared to the year ended December 31, 2016. The decrease is primarily a result of carried costs associated with the BP transactions and accrual adjustments from the Jubilee and TEN fields operator.

Depletion and depreciation. Depletion and depreciation increased $114.8 million during the year ended December 31, 2017, as compared with the year ended December 31, 2016, primarily as a result of depletion recognized related to the sale of eleven cargos of oil during 2017, as compared to seven cargos during the prior year.

Interest and other financing costs, net. Interest and other financing costs, net increased by $33.4 million primarily a result of TEN fields coming online in August 2016, which resulted in a $29.5 million decrease in capitalized interest during 2017.

Derivatives, net. During the years ended December 31, 2017 and 2016, we recorded losses of $60.0 million and $48.0 million, respectively, on our outstanding hedge positions. The losses recorded were a result of increases in the forward curve of oil prices during the respective periods.

Loss on equity method investments, net. Loss on equity method investments, net increased by $6.3 million during the year ended December 31, 2017 primarily a result of $11.5 million loss recognized on our equity method investment in KBSL offset by a $5.2 million gain recognized on our equity method investment in KTIPI.

Other expenses, net. Other expenses, net decreased by $17.8 million during the year ended December 31, 2017 primarily a result of a $6.3 million decrease in disputed charges and related costs and a $14.0 million decrease in inventory impairments partially offset by $3.5 million in insurance settlements related to the riser claim in 2016.

Income tax expense (benefit). The Company’s effective tax rates for the years ended December 31, 2017 and 2016 were 25% and 4%, respectively. The effective tax rates for the periods presented were impacted by losses, primarily related to exploration expenses, incurred in jurisdictions in which we are not subject to taxes and losses incurred in jurisdictions in which we have valuation allowances against our deferred tax assets and therefore we do not realize any tax benefit on such expenses or losses as well as the impact of the changes in U.S. income tax law. The effective tax rate in Ghana is impacted by timing of non-deductible expenditures incurred associated with the damage to the turret bearing, due to the expected recovery from insurance proceeds. Any such insurance recoveries would not be subject to income tax. Income tax expense increased by $55.7 million during the year ended December 31, 2017, as compared with the year ended December 31, 2016, primarily as a result of higher oil revenue in Ghana and mark-to-market gains on our oil derivatives and the impact of changes in U.S. tax law, partially offset by higher depletion and depreciation associated with TEN production.

Table of Contents

Year Ended December 31, 2016 vs. 2015

	Years Ended December 31,		Increase
	2016	2015	(Decrease)
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	$310,377	$446,696	$(136,319)
Gain on sale of assets	—	24,651	(24,651)
Other income	74,978	209	74,769
Total revenues and other income	385,355	471,556	(86,201)
Costs and expenses:			
Oil and gas production	119,367	105,336	14,031
Facilities insurance modifications	14,961	—	14,961
Exploration expenses	202,280	156,203	46,077
General and administrative	87,623	136,809	(49,186)
Depletion and depreciation	140,404	155,966	(15,562)
Interest and other financing costs, net	44,147	37,209	6,938
Derivatives, net	48,021	(210,649)	258,670
Other expenses, net	23,116	5,246	17,870
Total costs and expenses	679,919	386,120	293,799
Income (loss) before income taxes	(294,564)	85,436	(380,000)
Income tax expense (benefit)	(10,784)	155,272	(166,056)
Net loss	$(283,780)	$(69,836)	$(213,944)

Oil and gas revenue. Oil and gas revenue decreased by $136.3 million as a result of seven cargos sold during the year ended December 31, 2016 as compared to nine cargos during the year ended December 31, 2015, and as a result of a lower realized price per barrel. We lifted and sold 6,756 MBbl at an average realized price per barrel of $45.94 in 2016 and 8,538 MBbl at an average realized price per barrel of $52.32 in 2015.

Gain on sale of assets. During the year ended December 31, 2015, we closed a farm-out agreement with Chevron. As part of the transaction, we received proceeds in excess of our book basis, resulting in a gain of $24.7 million.

Other income. During the year ended December 31, 2016, we recognized $74.8 million of LOPI proceeds related to the turret bearing issue on the Jubilee FPSO.

Oil and gas production. Oil and gas production costs increased by $14.0 million during the year ended December 31, 2016 as compared to the year ended December 31, 2015. The 2016 costs were impacted by increased costs associated with the new operating procedures related to the turret bearing issue while the 2015 costs were impacted by higher workover costs in the Jubilee Field.

Facilities insurance modifications. During the year ended December 31, 2016, we incurred $15.0 million of facilities modification costs associated with the long-term solution to convert the FPSO to a permanently spread moored facility which we expect to substantially recover from our insurance policy.

Exploration expenses. Exploration expenses increased by $46.1 million during the year ended December 31, 2016, as compared to the year ended December 31, 2015. The increase is primarily a result of $107.7 million of stacked rig costs in 2016 and an increase of $31.5 million in seismic and geological and geophysical costs partially mitigated by $94.0 million of unsuccessful well costs in 2015 primarily for the Western Sahara CB-1 exploration well.

General and administrative. General and administrative costs decreased by $49.2 million during the year ended December 31, 2016, as compared to the year ended December 31, 2015. The decrease is primarily a result of a decrease in non-cash stock-based compensation and effective cost control.

Table of Contents

Depletion and depreciation. Depletion and depreciation decreased $15.6 million during the year ended December 31, 2016, as compared with the year ended December 31, 2015, primarily as a result of depletion recognized related to the sale of seven cargos of oil during 2016, as compared to nine cargos during the prior year.

Interest and other financing costs, net. Interest expense increased by $6.9 million during the year ended December 31, 2016, as compared to the year ended December 31, 2015. Higher gross interest costs on a larger debt balance and a full year of interest in 2016 on the 2021 Senior Notes totaling $14.2 million were partially offset by $7.4 million of higher capitalized interest during the current year as compared to the prior year.

Derivatives, net. During the years ended December 31, 2016 and 2015, we recorded a loss of $48.0 million and a gain of $210.6 million, respectively, on our outstanding hedge positions. The loss recorded in 2016 was a result of increases in the forward oil price curve and the gain recorded in 2015 was a result of decreases in the forward oil price curve.

Other expenses, net. Other expenses, net increased by $17.9 million during the year ended December 31, 2016, as compared to the year ended December 31, 2015, primarily as a result of a $14.9 million inventory write off and $11.3 million in disputed charges and related costs offset by $4.0 million of insurance proceeds related to the damaged riser.

Income tax expense (benefit). The Company's effective tax rates for the years ended December 31, 2016 and 2015 were a tax benefit of 4% and a tax expense of 182%, respectively. The effective tax rates for the periods presented were impacted by losses, primarily related to exploration expenses, incurred in jurisdictions in which we are not subject to taxes and losses incurred in jurisdictions in which we have valuation allowances against our deferred tax assets and therefore we do not realize any tax benefit on such expenses or losses. The effective tax rate in Ghana is impacted by non-deductible expenditures associated with the damage to the turret bearing which we expect to recover from insurance proceeds. Any such insurance recoveries would not be subject to income tax. Income tax expense decreased by $166.1 million during the year ended December 31, 2016, as compared with the year ended December 31, 2015, primarily as a result of lower revenue in Ghana.

Liquidity and Capital Resources

We are actively engaged in an ongoing process of anticipating and meeting our funding requirements related to exploring for and developing oil and natural gas resources along the Atlantic Margins. We have historically met our funding requirements through cash flows generated from our operating activities and obtained additional funding from issuances of equity and debt as well as partner carries. In relation to cash flow generated from our operating activities, if we are unable to continuously export associated natural gas in large quantities, which causes potential production restraints, then the Company's cash flows from operations will be adversely affected. In the past, we have experienced equipment failures, and we are currently working to fully remediate the turret bearing issue on the Jubilee FPSO. This equipment downtime negatively impacted oil production, and we are in the process of repairing the current mechanical issues and implementing a long-term solution for the turret bearing issue.

While we are presently in a strong financial position, a future decline in oil prices, if prolonged, could negatively impact our ability to generate sufficient operating cash flows to meet our funding requirements. It could also impact the borrowing base available under the Facility or the related debt covenants. Commodity prices are volatile and future prices cannot be accurately predicted. We maintain a hedging program to partially mitigate the price volatility. Our investment decisions are based on longer term commodity prices based on the long term nature of our projects and development plans. Also, BP has agreed to partially carry our exploration, appraisal and development program in Mauritania and Senegal over the next several years. Current commodity prices, our hedging program, partner carries and our current liquidity position support our capital program for 2018.

As such, our 2018 capital budget is based on our development plans for Ghana and our exploration and appraisal program.

Our future financial condition and liquidity can be impacted by, among other factors, the success of our exploration and appraisal drilling program, the number of commercially viable oil and natural gas discoveries made and the quantities of oil and natural gas discovered, the speed with which we can bring such discoveries to production, the reliability of our oil and gas production facilities, our ability to continuously export oil and gas, our ability to secure and maintain partners and their alignment with respect to capital plans, the actual cost of exploration, appraisal and development of our oil and natural gas assets, and coverage of any claims under our insurance policies.

As part of the Facility amendment and restatement process, the lenders approved a redetermination, setting the borrowing base under our Facility at $1.5 billion (effective February 22, 2018). The borrowing base calculation includes value related to the Jubilee, TEN, Ceiba and Okume fields.

Table of Contents

Sources and Uses of Cash

The following table presents the sources and uses of our cash and cash equivalents for the years ended December 31, 2017, 2016 and 2015:

	Years Ended December 31,		
	2017	2016	2015
	(In thousands)		
Sources of cash, cash equivalents and restricted cash:			
Net cash provided by operating activities	$236,617	$52,077	$440,779
Net proceeds from issuance of senior secured notes	—	—	206,774
Borrowings under long-term debt	200,000	450,000	100,000
Proceeds on sale of assets	222,068	210	28,692
	658,685	502,287	776,245
Uses of cash, cash equivalents and restricted cash:			
Oil and gas assets	140,495	535,975	823,642
Other property	2,858	1,998	1,483
Equity method investment	231,280	—	—
Payments on long-term debt	250,000	—	200,000
Purchase of treasury stock	2,194	1,981	18,110
Deferred financing costs	67	—	9,030
	626,894	539,954	1,052,265
Increase (decrease) in cash, cash equivalents and restricted cash	$31,791	$(37,667)	$(276,020)

Net cash provided by operating activities. Net cash provided by operating activities in 2017 was $236.6 million compared with net cash provided by operating activities of $52.1 million in 2016 and $441 million in 2015, respectively. The increase in cash provided by operating activities in the year ended December 31, 2017 when compared to the same period in 2016 is primarily a result of an increase in oil and gas revenue combined with LOPI proceeds, net and a decrease in exploration expense related to the stacked rig costs and rig option cancellation payment as well as a decrease in derivative cash settlements. The decrease in cash provided by operating activities in the year ended December 31, 2016 when compared to the same period in 2015 was primarily a result of a decrease in results from operations driven by lower barrels sold related to the turret bearing issue and lower realized revenue per barrel sold.

The following table presents our liquidity and financial position as of December 31, 2017:

	December 31, 2017 (In thousands)
Cash and cash equivalents	$ 233,412
Restricted cash	71,574
Senior Notes at par	525,000
Drawings under the Facility	800,000
Net debt	$ 1,020,014
Availability under the Facility	$ 500,811
Availability under the Corporate Revolver	$ 400,000
Available borrowings plus cash and cash equivalents	$ 1,134,223

Table of Contents

Capital Expenditures and Investments

We expect to incur capital costs as we:

- drill additional wells in the Jubilee and TEN Fields;
- fund asset integrity projects at Jubilee;
- execute exploration and appraisal activities in a number of our exploration license areas, including drilling two exploration wells in Suriname, and
- acquire and analyze seismic on existing licenses, pursue new ventures and manage our rig activities.

We have relied on a number of assumptions in budgeting for our future activities. These include the number of wells we plan to drill, our participating and carried interests in our prospects including disproportionate payment amounts, the costs involved in developing or participating in the development of a prospect, the timing of third party projects, our ability to utilize our available drilling rig capacity, the availability of suitable equipment and qualified personnel and our cash flows from operations. We also evaluate potential corporate and asset acquisition opportunities to support and expand our asset portfolio which may impact our budget assumptions. These assumptions are inherently subject to significant business, political, economic, regulatory, environmental and competitive uncertainties, contingencies and risks, all of which are difficult to predict and many of which are beyond our control. We may need to raise additional funds more quickly if market conditions deteriorate; or one or more of our assumptions proves to be incorrect or if we choose to expand our acquisition, exploration, appraisal, development efforts or any other activity more rapidly than we presently anticipate. We may decide to raise additional funds before we need them if the conditions for raising capital are favorable. We may seek to sell equity or debt securities or obtain additional bank credit facilities. The sale of equity securities could result in dilution to our shareholders. The incurrence of additional indebtedness could result in increased fixed obligations and additional covenants that could restrict our operations.

2018 Capital Program

We estimate we will spend approximately $300 million of capital, net of carry amounts related to the Mauritania and Senegal transactions with BP, for the year ending December 31, 2018. This capital expenditure budget consists of:

- approximately $110 million for developmental related expenditures offshore Ghana, largely focused on additional drilling in the Jubilee and TEN fields;
- approximately $50 million for exploration and appraisal activities, including drilling two exploration wells in Suriname;
- approximately $80 million related to seismic acquisition and processing across our portfolio to mature drilling opportunities;
- approximately $50 million for new ventures; and
- approximately $10 million related to corporate and other capital expenditures.

The ultimate amount of capital we will spend may fluctuate materially based on market conditions and the success of our drilling results among other factors. Our future financial condition and liquidity will be impacted by, among other factors, our level of production of oil and the prices we receive from the sale of oil, our ability to effectively hedge future production volumes, the success of our exploration and appraisal drilling program, the number of commercially viable oil and natural gas discoveries made and the quantities of oil and natural gas discovered, the speed with which we can bring such discoveries to production, our partners' alignment with respect to capital plans, and the actual cost of exploration, appraisal and development of our oil and natural gas assets, and coverage of any claims under our insurance policies.

Significant Sources of Capital

Facility

As of December 31, 2017, borrowings under the Facility totaled $800.0 million including $200 million drawn for the KTIPI investment, and the undrawn availability under the Facility was $500.8 million.

Table of Contents

In February 2018, the Company amended and restated the Facility with a total commitment of $1.5 billion from a number of financial institutions with additional commitments up to $0.5 billion being available if the existing financial institutions increase their commitments or if commitments from new financial institutions are added. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities. As part of the debt refinancing in February 2018, the repayment of borrowings under the existing facility attributable to financial institutions that did not participate in the amended Facility was accounted for as an extinguishment of debt, and $5.7 million of existing unamortized debt issuance costs attributable to those participants were expensed in the first quarter of 2018. As of December 31, 2017, we have $23.6 million of unamortized issuance costs related to the Facility, which will be amortized over the remaining term of the Facility, excluding the $5.7 million expensed in the first quarter of 2018.

As part of the amendment and restatement process, the lenders approved a redetermination, setting the borrowing base under our Facility at $1.5 billion (effective February 22, 2018). The borrowing base calculation includes value related to the Jubilee, TEN, Ceiba and Okume fields. The following amendments to the terms of the existing facility, subject to certain conditions and exceptions, include without limitation:

- the extension of the maturity date to March 31, 2025 (unless otherwise terminated pursuant to the amended and restated Facility);
- the extension of the amortization schedule such that amortization of principal is to commence in March 31, 2022 and continue in equal amounts every six months thereafter until the maturity date;
- commitment fees lowered from 40% to 30% of the applicable interest margin;
- maintaining interest margin at LIBOR plus 3.25% for the next four years;
- the inclusion of the Company’s recently acquired producing assets in Equatorial Guinea in the calculation of borrowing base amounts as well as the Company’s option to include the Greater Tortue development in the future following final investment decision, up to $500 million in the aggregate; and
- the addition of Kosmos Energy Finance International, Kosmos Energy Investments Senegal Limited, Kosmos Energy Equatorial Guinea, Kosmos Energy Senegal and Kosmos Energy Mauritania as additional guarantors and pledged subsidiaries.

Interest is the aggregate of the applicable margin (3.25% to 4.50%, depending on the length of time that has passed from the date the Facility was entered into) and LIBOR. Interest is payable on the last day of each interest period (and, if the interest period is longer than six months, on the dates falling at six-month intervals after the first day of the interest period). We pay commitment fees on the undrawn and unavailable portion of the total commitments, if any. Commitment fees are equal to 30% per annum of the then-applicable respective margin when a commitment is available for utilization and, equal to 20% per annum of the then-applicable respective margin when a commitment is not available for utilization. We recognize interest expense in accordance with ASC 835—Interest, which requires interest expense to be recognized using the effective interest method. We determined the effective interest rate based on the estimated level of borrowings under the Facility.

The Facility provides a revolving credit and letter of credit facility. The availability period for the revolving- credit facility, as amended in February 2018 expires one month prior to the final maturity date. The letter of credit facility expires on the final maturity date. The available facility amount is subject to borrowing base constraints and, beginning on March 31, 2022, outstanding borrowings will be constrained by an amortization schedule. The Facility has a final maturity date of March 31, 2025. As of December 31, 2017, we had no letters of credit issued under the Facility.

We have the right to cancel all the undrawn commitments under the Facility. The amount of funds available to be borrowed under the Facility, also known as the borrowing base amount, is determined each year on March 31. The borrowing base amount is based on the sum of the net present values of net cash flows and relevant capital expenditures reduced by certain percentages as well as value attributable to certain assets’ reserves and/or resources in Ghana and Equatorial Guinea.

If an event of default exists under the Facility, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Facility over certain assets held by our subsidiaries. The Facility contains customary cross default provisions.

We were in compliance with the financial covenants contained in the Facility as of September 30, 2017 (the most recent assessment date), which requires the maintenance of:

- the field life cover ratio (as defined in the glossary), not less than 1.30x; and

Table of Contents

- the loan life cover ratio (as defined in the glossary), not less than 1.10x; and
- the debt cover ratio (as defined in the glossary), not more than 3.5x; and
- the interest cover ratio (as defined in the glossary), not less than 2.25x.

Corporate Revolver

In November 2012, we secured a Corporate Revolver from a number of financial institutions which, as amended in June 2015, has an availability of $400.0 million. The Corporate Revolver is available for all subsidiaries for general corporate purposes and for oil and gas exploration, appraisal and development programs.

As of December 31, 2017, there were no borrowings outstanding under the Corporate Revolver and the undrawn availability under the Corporate Revolver was $400.0 million.

Interest is the aggregate of the applicable margin (6.0%), LIBOR and mandatory cost (if any, as defined in the Corporate Revolver). Interest is payable on the last day of each interest period (and, if the interest period is longer than six months, on the dates falling at six month intervals after the first day of the interest period). We pay commitment fees on the undrawn portion of the total commitments. Commitment fees, as amended in June 2015, for the lenders are equal to 30% per annum of the respective margin when a commitment is available for utilization.

The Corporate Revolver, as amended in June 2015, expires on November 23, 2018. The available amount is not subject to borrowing base constraints. We have the right to cancel all the undrawn commitments under the Corporate Revolver. We are required to repay certain amounts due under the Corporate Revolver with sales of certain subsidiaries or sales of certain assets. If an event of default exists under the Corporate Revolver, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Corporate Revolver over certain assets held by us. The Corporate Revolver contains customary cross default provisions.

We were in compliance with the financial covenants contained in the Corporate Revolver as of September 30, 2017 (the most recent assessment date), which requires the maintenance of:

- the debt cover ratio (as defined in the glossary), not more than 3.5x; and
- the interest cover ratio (as defined in the glossary), not less than 2.25x.

The U.S. and many foreign economies continue to experience uncertainty driven by varying macroeconomic conditions. Although some of these economies have shown signs of improvement, macroeconomic recovery remains uneven. Uncertainty in the macroeconomic environment and associated global economic conditions have resulted in extreme volatility in credit, equity, and foreign currency markets, including the European sovereign debt markets and volatility in various other markets. If any of the financial institutions within our Facility or Corporate Revolver are unable to perform on their commitments, our liquidity could be impacted. We actively monitor all of the financial institutions participating in our Facility and Corporate Revolver. None of the financial institutions have indicated to us that they may be unable to perform on their commitments. In addition, we periodically review our banking and financing relationships, considering the stability of the institutions and other aspects of the relationships. Based on our monitoring activities, we currently believe our banks will be able to perform on their commitments.

Revolving Letter of Credit Facility

In July 2013, we entered into a revolving letter of credit facility agreement (“LC Facility”). The size of the LC Facility is $75.0 million, as amended in July 2015, with additional commitments up to $50.0 million being available if the existing lender increases its commitments or if commitments from new financial institutions are added. The LC Facility provides that we shall maintain cash collateral in an amount equal to at least 75% of all outstanding letters of credit under the LC Facility, provided that during the period of any breach of certain financial covenants, the required cash collateral amount shall increase to 100%.

In July 2016, we amended and restated the LC Facility, extending the maturity date to July 2019. Other amendments included increasing the margin from 0.5% to 0.8% per annum on amounts outstanding, adding a commitment fee payable quarterly in arrears at an annual rate equal to 0.65% on the available commitment amount and providing for issuance fees to be payable to the lender per new issuance of a letter of credit. We may voluntarily cancel any commitments available under the LC Facility at any time. During the first quarter of 2017, the LC Facility size was increased to $115.0 million and in April 2017, we reduced the size of our LC Facility to $70 million. In February 2018, the LC Facility was increased to $73 million to facilitate the issuance of additional letters of credit. As of

December 31, 2017, there were eight outstanding letters of credit totaling $60.3 million under the LC Facility. The LC Facility contains customary cross default provisions.

Table of Contents

7.875% Senior Secured Notes due 2021

During August 2014, the Company issued $300.0 million of Senior Notes and received net proceeds of approximately $292.5 million after deducting discounts, commissions and deferred financing costs. The Company used the net proceeds to repay a portion of the outstanding indebtedness under the Facility and for general corporate purposes.

During April 2015, we issued an additional $225.0 million Senior Notes and received net proceeds of $206.8 million after deducting discounts, commissions and other expenses. We used the net proceeds to repay a portion of the outstanding indebtedness under the Facility and for general corporate purposes. The additional $225.0 million of Senior Notes have identical terms to the initial $300.0 million Senior Notes, other than the date of issue, the initial price, the first interest payment date and the first date from which interest accrued.

The Senior Notes mature on August 1, 2021. Interest is payable semi annually in arrears each February 1 and August 1 commencing on February 1, 2015 for the initial $300.0 million Senior Notes and August 1, 2015 for the additional $225.0 million Senior Notes. The Senior Notes are secured (subject to certain exceptions and permitted liens) by a first ranking fixed equitable charge on all shares held by us in our direct subsidiary, Kosmos Energy Holdings. The Senior Notes are currently guaranteed on a subordinated, unsecured basis by our existing restricted subsidiaries that guarantee the Facility and the Corporate Revolver, and, in certain circumstances, the Senior Notes will become guaranteed by certain of our other existing or future restricted subsidiaries (the “Guarantees”).

Redemption and Repurchase. On or after August 1, 2017, the Company may redeem all or a part of the Senior Notes at the redemption prices (expressed as percentages of principal amount) set forth below plus accrued and unpaid interest:

Year	Percentage
On or after August 1, 2017, but before August 1, 2018	103.9 %
On or after August 1, 2018, but before August 1, 2019	102.0 %
On or after August 1, 2019 and thereafter	100.0 %

We may also redeem the Senior Notes in whole, but not in part, at any time if changes in tax laws impose certain withholding taxes on amounts payable on the Senior Notes at a price equal to the principal amount of the Senior Notes plus accrued interest and additional amounts, if any, as may be necessary so that the net amount received by each holder after any withholding or deduction on payments of the Senior Notes will not be less than the amount such holder would have received if such taxes had not been withheld or deducted.

Upon the occurrence of a change of control triggering event as defined under the Indenture, the Company will be required to make an offer to repurchase the Senior Notes at a repurchase price equal to 101% of the principal amount, plus accrued and unpaid interest to, but excluding, the date of repurchase.

If we sell assets, under certain circumstances outlined in the Indenture, we will be required to use the net proceeds to make an offer to purchase the Senior Notes at an offer price in cash in an amount equal to 100% of the principal amount of the Senior Notes, plus accrued and unpaid interest to, but excluding, the repurchase date.

Covenants. The Indenture restricts our ability and the ability of our restricted subsidiaries to, among other things: incur or guarantee additional indebtedness, create liens, pay dividends or make distributions in respect of capital stock, purchase or redeem capital stock, make investments or certain other restricted payments, sell assets, enter into agreements that restrict the ability of our subsidiaries to make dividends or other payments to us, enter into transactions with affiliates, or effect certain consolidations, mergers or amalgamations. These covenants are subject to a number of important qualifications and exceptions. Certain of these covenants will be terminated if the Senior Notes are assigned an investment grade rating by both Standard & Poor’s Rating Services and Fitch Ratings Inc. and no default or event of default has occurred and is continuing.

Collateral. The Senior Notes are secured (subject to certain exceptions and permitted liens) by a first ranking fixed equitable charge on all currently outstanding shares, additional shares, dividends or other distributions paid in respect of such shares or any other property derived from such shares, in each case held by us in relation to the Company’s direct subsidiary, Kosmos Energy Holdings, pursuant to the terms of the Charge over Shares of Kosmos Energy Holdings dated November 23, 2012, as amended and restated on March 14, 2014, between the Company and BNP Paribas as Security and Intercreditor Agent. The Senior Notes share pari passu in the benefit of such equitable charge based on the respective amounts of the obligations under the Indenture and the amount of obligations under the

Corporate Revolver. The Guarantees are not secured.

Table of Contents

Contractual Obligations

The following table summarizes by period the payments due for our estimated contractual obligations as of December 31, 2017:

	Payments Due By Year(4)						
	Total	2018	2019	2020	2021	2022	Thereafter
Principal debt repayments(1)	$1,325,000	$ —	$200,377	$404,971	$719,652	$ —	$ —
Interest payments on long-term debt(2)	293,194	93,603	85,846	68,457	45,288	—	—
Operating leases(3)	12,626	4,981	4,370	484	419	418	1,954

(1) Includes the scheduled principal maturities for the $525.0 million aggregate principal amount of Senior Notes issued in August 2014 and April 2015 and the Facility. The scheduled maturities of debt related to the Facility are based on the level of borrowings and the estimated future available borrowing base as of December 31, 2017. Any increases or decreases in the level of borrowings or increases or decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter. As of December 31, 2017, there were no borrowings under the Corporate Revolver.

(2) Based on outstanding borrowings as noted in (1) above and the LIBOR yield curves at the reporting date and commitment fees related to the Facility and Corporate Revolver and interest on the Senior Notes.

(3) Primarily relates to corporate office and foreign office leases.

(4) Does not include purchase commitments for jointly owned fields and facilities where we are not the operator and excludes commitments for exploration activities, including well commitments and seismic obligations, in our petroleum contracts.

We currently have a commitment to drill one exploration well in Mauritania. In Mauritania, our partner is obligated to fund our share of the cost of the exploration well, subject to their maximum $228 million cumulative exploration and appraisal carry covering both our Mauritania and Senegal blocks. In Equatorial Guinea, Mauritania and Cote d'Ivoire, we have 3D seismic requirements of approximately 6,000 square kilometers, 7,600 square kilometers and 12,000 square kilometers, respectively.

Table of Contents

The following table presents maturities by expected debt maturity dates, the weighted average interest rates expected to be paid on the Facility given current contractual terms and market conditions, and the debt's estimated fair value. Weighted average interest rates are based on implied forward rates in the yield curve at the reporting date. This table does not take into account amortization of deferred financing costs.

	Years Ending December 31,						Asset (Liability) Fair Value at December 31,
	2018	2019	2020	2021	2022	Thereafter	2017
	(In thousands, except percentages)						
Fixed rate debt:							
Senior Notes	$—	$—	$—	$525,000	$ —	$ —	$(542,472)
Fixed interest rate	7.88 %	7.88 %	7.88 %	7.88 %	—	—	
Variable rate debt:							
Facility(1)	$—	$200,377	$404,971	$194,652	$ —	$ —	$(800,000)
Weighted average interest rate(2)	5.40 %	5.87 %	6.43 %	6.69 %	—	—	
Capped interest rate swaps:							
Notional debt amount ($200,000)	$—	$—	$—	$—	$ —	$ —	$1,017
Cap	3.00 %	—	—	—	—	—	
Average fixed rate payable(3)	1.23 %	—	—	—	—	—	
Variable rate receivable(4)	1.77 %	—	—	—	—	—	

(1) The amounts included in the table represent principal maturities only. The scheduled maturities of debt are based on the level of borrowings and the available borrowing base as of December 31, 2017. Any increases or decreases in the level of borrowings or increases or decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter. As of December 31, 2017, there were no borrowings under the Corporate Revolver.

(2) Based on outstanding borrowings as noted in (1) above and the LIBOR yield curves plus applicable margin at the reporting date. Excludes commitment fees related to the Facility and Corporate Revolver.

(3) We expect to pay the fixed rate if 1-month LIBOR is below the cap, and pay the market rate less the spread between the cap and the fixed rate if LIBOR is above the cap, net of the capped interest rate swaps.

(4) Based on implied forward rates in the yield curve at the reporting date.

Off Balance Sheet Arrangements

We may enter into off balance sheet arrangements and transactions that can give rise to material off balance sheet obligations. As of December 31, 2017, our material off balance sheet arrangements and transactions include operating leases and undrawn letters of credit. There are no other transactions, arrangements, or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect Kosmos' liquidity or availability of or requirements for capital resources.

Critical Accounting Policies

This discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements, which have been prepared in accordance with generally accepted accounting principles in the United States. The preparation of our financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities as of the date the financial statements are available to be issued. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time.

Actual results may vary from our estimates. Our significant accounting policies are detailed in “Item 8. Financial Statements and Supplementary Data—Note 2—Accounting Policies.” We have outlined below certain accounting policies that are of particular importance to the presentation of our financial position and results of operations and require the application of significant judgment or estimates by our management.

Revenue Recognition. We use the sales method of accounting for oil and gas revenues. Under this method, 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. These differences result in a condition known in the industry as a production imbalance. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves on such property. As of December 31, 2017 and 2016, we had no oil and gas imbalances recorded in our consolidated financial statements.

Our oil and gas revenues are based on provisional price contracts which contain an embedded derivative that is required to be separated from the host contract for accounting purposes. The host contract is the receivable from oil sales at the spot price on the date of sale. The embedded derivative, which is not designated as a hedge for accounting purposes, is marked to market through oil and gas revenue each period until the final settlement occurs, which generally is limited to the month after the sale occurs.

Exploration and Development Costs. We follow the successful efforts method of accounting for our oil and gas properties. Acquisition costs for proved and unproved properties are capitalized when incurred. Costs of unproved properties are transferred to proved properties when a determination that proved reserves have been found. Exploration costs, including geological and geophysical costs and costs of carrying unproved properties, are charged to expense as incurred. Exploratory drilling costs are capitalized when incurred. If exploratory wells are determined to be commercially unsuccessful or dry holes, the applicable costs are expensed. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized. Costs incurred to operate and maintain wells and equipment and to lift crude oil and natural gas to the surface are expensed.

Receivables. Our receivables consist of joint interest billings, oil sales and other receivables. For our oil sales receivable, we require a letter of credit to be posted to secure the outstanding receivable. Receivables from joint interest owners are stated at amounts due, net of any allowances for doubtful accounts. We determine our allowance by considering the length of time past due, future net revenues of the debtor’s ownership interest in oil and natural gas properties we operate, and the owner’s ability to pay its obligation, among other things.

Income Taxes. We account for income taxes as required by the ASC 740—Income Taxes (“ASC 740”). We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal, state and international tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of changes in tax laws or tax rates, tax credits, and net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood that we will be able to realize or utilize our deferred tax assets. If realization is not more likely than not, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in no benefit for the deferred tax amounts. As of December 31, 2017 and 2016, we have a valuation allowance to reduce certain deferred tax assets to amounts that are more likely than not to be realized. If our estimates and judgments regarding our ability to realize our deferred tax assets change, the benefits associated with those deferred tax assets may increase or decrease in the period our estimates and judgments change. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary.

ASC 740 provides a more likely than not standard in evaluating whether a valuation allowance is necessary after weighing all of the available evidence. When evaluating the need for a valuation allowance, we consider all available positive and negative evidence, including the following:

- the status of our operations in the particular taxing jurisdiction, including whether we have commenced production from a commercial discovery;
- whether a commercial discovery has resulted in significant proved reserves that have been independently verified;

- the amounts and history of taxable income or losses in a particular jurisdiction;
- projections of future income, including the sensitivity of such projections to changes in production volumes and prices;
- the existence, or lack thereof, of statutory limitations on the period that net operating losses may be carried forward in a jurisdiction; and

- the creation and timing of future income associated with the reversal of deferred tax liabilities in excess of deferred tax assets.

Derivative Instruments and Hedging Activities. We utilize oil derivative contracts to mitigate our exposure to commodity price risk associated with our anticipated future oil production. These derivative contracts consist of collars, put options, call options and swaps. We also use interest rate derivative contracts to mitigate our exposure to interest rate fluctuations related to our long term debt. Our derivative financial instruments are recorded on the balance sheet as either assets or a liabilities measured at fair value. We do not apply hedge accounting to our oil derivative contracts. Effective June 1, 2010, we discontinued hedge accounting on our interest rate swap contracts and accordingly the changes in the fair value of the instruments are recognized in earnings in the period of change. The effective portions of the discontinued hedges as of May 31, 2010, were included in accumulated other comprehensive income or loss ("AOCI") in the equity section of the accompanying consolidated balance sheets, and were transferred to earnings when the hedged transactions settled.

Estimates of Proved Oil and Natural Gas Reserves. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and assessment of impairment of our oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. As additional proved reserves are discovered, reserve quantities and future cash flows will be estimated by independent petroleum consultants and prepared in accordance with guidelines established by the SEC and the FASB. The accuracy of these reserve estimates is a function of:

- the engineering and geological interpretation of available data;
- estimates of the amount and timing of future operating cost, production taxes, development cost and workover cost;
- the accuracy of various mandated economic assumptions; and
- the judgments of the persons preparing the estimates.

Asset Retirement Obligations. We account for asset retirement obligations as required by the ASC 410—Asset Retirement and Environmental Obligations. Under these standards, the fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, the liability is recognized when a reasonable estimate of fair value can be made. If a tangible long lived asset with an existing asset retirement obligation is acquired, a liability for that obligation shall be recognized at the asset's acquisition date as if that obligation were incurred on that date. In addition, a liability for the fair value of a conditional asset retirement obligation is recorded if the fair value of the liability can be reasonably estimated. We capitalize the asset retirement costs by increasing the carrying amount of the related long lived asset by the same amount as the liability. We record increases in the discounted abandonment liability resulting from the passage of time in depletion and depreciation in the consolidated statement of operations. Estimating the future restoration and removal costs requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Additionally, asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. 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 asset retirement obligations, a corresponding adjustment is made to the oil and gas property balance.

Impairment of Long Lived Assets. We review our long lived assets for impairment when changes in circumstances indicate that the carrying amount of an asset may not be recoverable. ASC 360—Property, Plant and Equipment requires an impairment loss to be recognized if the carrying amount of a long lived asset is not recoverable and exceeds its fair value. The carrying amount of a long lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. That assessment shall be based on the carrying amount of the asset at the date it is tested for recoverability, whether in use or under development. An impairment loss shall be measured as the amount by which the carrying amount of a long lived asset exceeds its fair value. Assets to be disposed of and assets not expected to provide any future service potential to us are recorded at the lower of carrying amount or fair value less cost to sell.

We believe the assumptions used in our undiscounted cash flow analysis to test for impairment are appropriate and result in a reasonable estimate of future cash flows. The undiscounted cash flows from the analysis exceeded the carrying amount of our long-lived assets. The most significant assumptions are the pricing and production estimates used in undiscounted cash flow analysis. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the evaluation.

Table of Contents

In order to evaluate the sensitivity of the assumptions, we assumed a hypothetical reduction in our production profile and lower pricing during the early years which still showed no impairment. If we experience further declines in oil pricing, increases in our estimated future expenditures or a decrease in our estimated production profile our long-lived assets could be at risk for impairment.

Consolidations / Equity Method of Accounting. The Consolidated Financial Statements include the accounts of our wholly-owned subsidiaries. They also include Kosmos' share of the undivided interest in certain assets, liabilities, revenues and expenses. Investments in corporate joint ventures, which we exercise significant influence over, are accounted for using the equity method of accounting.

Equity method investments are integral to our operations. The other parties, who also have an equity interest in these companies, are independent third parties. Kosmos does not invest in these companies in order to remove liabilities from its balance sheet.

New Accounting Pronouncements

See "Item 8. Financial Statements and Supplementary Data—Note 2—Accounting Policies" for a discussion of recent accounting pronouncements.

Item 7A. Qualitative and Quantitative Disclosures About Market Risk

The primary objective of the following information is to provide forward looking quantitative and qualitative information about our potential exposure to market risks. The term "market risks" as it relates to our currently anticipated transactions refers to the risk of loss arising from changes in commodity prices and interest rates. These disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward looking information provides indicators of how we view and manage ongoing market risk exposures. We enter into market risk sensitive instruments for purposes other than to speculate.

We manage market and counterparty credit risk in accordance with our policies. In accordance with these policies and guidelines, our management determines the appropriate timing and extent of derivative transactions. See "Item 8. Financial Statements and Supplementary Data—Note 2—Accounting Policies, Note 8—Derivative Financial Instruments and Note 9—Fair Value Measurements" for a description of the accounting procedures we follow relative to our derivative financial instruments.

The following table reconciles the changes that occurred in fair values of our open derivative contracts during the year ended December 31, 2017:

	Derivative Contracts Assets (Liabilities)		
	Commodities	Interest Rates	Total
	(In thousands)		
Fair value of contracts outstanding as of December 31, 2016	$ 1,638	$ 53	$ 1,691
Changes in contract fair value	(72,470)	648	(71,822)
Contract maturities	(26,204)	316	(25,888)
Fair value of contracts outstanding as of December 31, 2017	$ (97,036)	$ 1,017	$ (96,019)

Commodity Price Risk

The Company's revenues, earnings, cash flows, capital investments and, ultimately, future rate of growth are highly dependent on the prices we receive for our crude oil, which have historically been very volatile. Our oil sales are indexed against Dated Brent crude. Dated Brent prices in 2017 ranged between approximately $44 to $67 per barrel.

Commodity Derivative Instruments

We enter into various oil derivative contracts to mitigate our exposure to commodity price risk associated with anticipated future oil production. These contracts currently consist of collars, put options, call options and swaps. In regards to our obligations under our various commodity derivative instruments, if our production does not exceed our existing hedged positions, our exposure to our commodity derivative instruments would increase.

Table of Contents

Commodity Price Sensitivity

The following table provides information about our oil derivative financial instruments that were sensitive to changes in oil prices as of December 31, 2017:

			Weighted Average Dated Brent Price per Bbl						Asset (Liability) Fair Value at December 31,
Term	Type of Contract	MBbl	Net Deferred Premium Payable	Swap	Sold Put	Floor	Ceiling	Call	2017(2)
2018									
January — December	Swap with puts	2,000	$ —	$ 54.32	$ 40.00	$ —	$ —	$ —	$ (20,544)
July — December	Swap with puts	2,000	—	57.96	45.00	—	—	—	(12,068)
January — June	Swaps	1,000	—	57.25	—	—	—	—	(8,390)
January — December	Three-way collars	2,913	0.74	—	41.57	56.57	65.90	—	(10,270)
January — December	Four-way collars	3,000	1.06	—	40.00	50.00	61.33	70.00	(14,554)
January — December	Sold calls(1)	2,000	—	—	—	—	65.00	—	(6,739)
2019									
January — December	Three-way collars	6,500	$ 0.18	$ —	$ 41.54	$ 51.54	$ 63.80	$ —	$ (19,750)
January — December	Two-way collars	2,000	1.62	—	—	55.00	65.00	—	(4,088)
January — December	Sold calls(1)	913	—	—	—	—	80.00	—	(633)

(1) Represents call option contracts sold to counterparties to enhance other derivative positions.

(2) Fair values are based on the average forward Dated Brent oil prices on December 31, 2017 which by year are: 2018—$64.96 and 2019—$61.00. These fair values are subject to changes in the underlying commodity price. The average forward Dated Brent oil prices based on February 21, 2018 market quotes by year are: 2018—$63.86 and 2019—$60.37.

In January 2018, we entered into three-way costless collar contracts for 1.0 MMBbl from January 2019 through December 2019 with a sold put price of $45.00, a floor price of $55.00 per barrel and a ceiling price of $72.90 per barrel. The contracts are indexed to Dated Brent prices.

In February 2018, we sold 2.0 MMBbl of put contracts from January 2019 through December 2019 with a strike of $47.50 per barrel. We used part of the proceeds to increase our upside by purchasing 1.0 MMBbl of calls in the second half of 2018 with a strike price of $70.00 per barrel. These contracts are indexed to Dated Brent prices and have a net deferred premium receivable of $3.1 million.

At December 31, 2017, our open commodity derivative instruments were in a net liability position of $97.0 million. As of December 31, 2017, a hypothetical 10% price increase in the commodity futures price curves would decrease future pre tax earnings by approximately $95.5 million. Similarly, a hypothetical 10% price decrease would increase future pre tax earnings by approximately $89.5 million.

Interest Rate Derivative Instruments

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Contractual Obligations" for specific information regarding the terms of our interest rate derivative instruments that are sensitive to changes in interest rates.

Table of Contents

Interest Rate Sensitivity

At December 31, 2017, we had indebtedness outstanding under the Facility of $800.0 million, of which $600.0 million bore interest at floating rates after consideration of our fixed rate interest rate hedges. The interest rate on this indebtedness as of December 31, 2017 was approximately 4.6%. If LIBOR increased 10% at this level of floating rate debt, we would pay an additional $0.8 million in interest expense per year on the Facility. We pay commitment fees on the $500.8 million of undrawn availability and $199.2 million of unavailable commitments under the Facility and on the $400.0 million of undrawn availability under the Corporate Revolver at December 31, 2017, which are not subject to changes in interest rates.

As of December 31, 2017, the fair market value of our interest rate swaps was a net asset of approximately $1.0 million. If LIBOR increased by 10%, we estimate it would have a negligible impact on the fair market value of our interest rate swaps.

Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

	Page
Consolidated Financial Statements of Kosmos Energy Ltd.:	
Reports of Independent Registered Public Accounting Firm	88
Consolidated Balance Sheets as of December 31, 2017 and 2016	90
Consolidated Statements of Operations for the years ended December 31, 2017, 2016 and 2015	91
Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2017, 2016 and 2015	92
Consolidated Statements of Shareholders' Equity for the years ended December 31, 2017, 2016 and 2015	93
Consolidated Statements of Cash Flows for the years ended December 31, 2017, 2016 and 2015	94
Notes to Consolidated Financial Statements	95
Supplemental Oil and Gas Data (Unaudited)	122
Supplemental Quarterly Financial Information (Unaudited)	127

Table of Contents

Report of Independent Registered Public Accounting Firm
To the Shareholders and the Board of Directors of Kosmos Energy Ltd.
Opinion on the Financial Statements
We have audited the accompanying consolidated balance sheets of Kosmos Energy Ltd. (the Company) as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive income (loss), shareholders' equity and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and financial statement schedules listed in the Index at Item 15(a) (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 the Company at December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.
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 issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 26, 2018 expressed an unqualified opinion thereon.
Basis for Opinion
These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.
/s/ Ernst & Young LLP
We have served as the Company’s auditor since 2004.
Dallas, Texas
February 26, 2018

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Kosmos Energy Ltd.

Opinion on Internal Control over Financial Reporting

We have audited Kosmos Energy Ltd.'s internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Kosmos Energy Ltd (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 2017 consolidated financial statements of the Company and our report dated February 26, 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 Management's Annual Report on Internal Control over Financial Reporting appearing in Item 9A. 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 the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit 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, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and 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/ Ernst & Young LLP

Dallas, Texas

February 26, 2018

KOSMOS ENERGY LTD.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2017	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	$233,412	$194,057
Restricted cash	56,380	24,506
Receivables:		
Joint interest billings, net	134,565	63,249
Oil sales	—	54,195
Related party	780	—
Other	25,616	25,893
Inventories	71,861	74,380
Prepaid expenses and other	9,306	7,209
Derivatives	1,682	31,698
Total current assets	533,602	475,187
Property and equipment:		
Oil and gas properties, net	2,310,973	2,700,889
Other property, net	6,855	8,003
Property and equipment, net	2,317,828	2,708,892
Other assets:		
Equity method investment	236,514	—
Restricted cash	15,194	54,632
Long-term receivables - joint interest billings	34,941	45,663
Deferred financing costs, net of accumulated amortization of $13,951 and $11,213 at December 31, 2017 and December 31, 2016, respectively	2,510	5,248
Long-term deferred tax assets	22,517	37,827
Derivatives	39	3,808
Other	29,458	10,208
Total assets	$3,192,603	$3,341,465
Liabilities and shareholders’ equity		
Current liabilities:		
Accounts payable	$141,787	$220,627
Accrued liabilities	219,412	129,706
Derivatives	67,531	19,692
Total current liabilities	428,730	370,025
Long-term liabilities:		
Long-term debt, net	1,282,797	1,321,874
Derivatives	30,209	14,123
Asset retirement obligations	66,595	63,574
Deferred tax liabilities	476,548	482,221
Other long-term liabilities	10,612	8,449
Total long-term liabilities	1,866,761	1,890,241

Shareholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2017 and December 31, 2016	—	—
Common shares, $0.01 par value; 2,000,000,000 authorized shares; 398,599,457 and 395,859,061 issued at December 31, 2017 and December 31, 2016, respectively	3,986	3,959
Additional paid-in capital	2,014,525	1,975,247
Accumulated deficit	(1,073,202)	(850,410)
Treasury stock, at cost, 9,188,819 and 9,101,395 shares at December 31, 2017 and December 31, 2016, respectively	(48,197)	(47,597)
Total shareholders' equity	897,112	1,081,199
Total liabilities and shareholders' equity	$3,192,603	$3,341,465

See accompanying notes.

90

Table of Contents

KOSMOS ENERGY LTD.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)

	Years Ended December 31,		
	2017	2016	2015
Revenues and other income:			
Oil and gas revenue	$578,139	$310,377	$446,696
Gain on sale of assets	—	—	24,651
Other income, net	58,697	74,978	209
Total revenues and other income	636,836	385,355	471,556
Costs and expenses:			
Oil and gas production	126,850	119,367	105,336
Facilities insurance modifications, net	(820)	14,961	—
Exploration expenses	216,050	202,280	156,203
General and administrative	68,302	87,623	136,809
Depletion and depreciation	255,203	140,404	155,966
Interest and other financing costs, net	77,595	44,147	37,209
Derivatives, net	59,968	48,021	(210,649)
Loss on equity method investments, net	6,252	—	—
Other expenses, net	5,291	23,116	5,246
Total costs and expenses	814,691	679,919	386,120
Income (loss) before income taxes	(177,855)	(294,564)	85,436
Income tax expense (benefit)	44,937	(10,784)	155,272
Net loss	$(222,792)	$(283,780)	$(69,836)
Net loss per share:			
Basic	$(0.57)	$(0.74)	$(0.18)
Diluted	$(0.57)	$(0.74)	$(0.18)
Weighted average number of shares used to compute net loss per share:			
Basic	388,375	385,402	382,610
Diluted	388,375	385,402	382,610

See accompanying notes.

Table of Contents

KOSMOS ENERGY LTD.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS
(In thousands)

	Years Ended December 31,		
	2017	2016	2015
Net loss	$(222,792)	$(283,780)	$(69,836)
Other comprehensive loss:			
Reclassification adjustments for derivative gains included in net loss	—	—	(767)
Other comprehensive loss	—	—	(767)
Comprehensive loss	$(222,792)	$(283,780)	$(70,603)

See accompanying notes.

Table of Contents

KOSMOS ENERGY LTD.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(In thousands)

	Common Shares		Additional Paid-in	Accumulated	Accumulated other Comprehensive	Treasury	
	Shares	Amount	Capital	Deficit	Income	Stock	Total
Balance as of December 31, 2014	392,443	$ 3,924	$ 1,860,190	$ (494,850)	$ 767	$ (31,072)	$ 1,338,959
Equity-based compensation	—	—	75,267	—	—	—	75,267
Derivatives, net	—	—	—	—	(767)	—	(767)
Restricted stock awards and units	1,460	15	(15)	—	—	—	—
Restricted stock forfeitures	—	—	16	—	—	(16)	—
Purchase of treasury stock	—	—	(2,269)	—	—	(15,841)	(18,110)
Net loss	—	—	—	(69,836)	—	—	(69,836)
Balance as of December 31, 2015	393,903	3,939	1,933,189	(564,686)	—	(46,929)	1,325,513
Equity-based compensation	—	—	43,391	(1,944)	—	—	41,447
Restricted stock awards and units	1,956	20	(20)	—	—	—	—
Restricted stock forfeitures	—	—	2	—	—	(2)	—
Purchase of treasury stock	—	—	(1,315)	—	—	(666)	(1,981)
Net loss	—	—	—	(283,780)	—	—	(283,780)
Balance as of December 31, 2016	395,859	3,959	1,975,247	(850,410)	—	(47,597)	1,081,199
Equity-based compensation	—	—	40,899	—	—	—	40,899
Restricted stock awards and units	2,740	27	(27)	—	—	—	—
Purchase of treasury stock	—	—	(1,594)	—	—	(600)	(2,194)
Net loss	—	—	—	(222,792)	—	—	(222,792)
Balance as of December 31, 2017	398,599	3,986	2,014,525	(1,073,202)	—	(48,197)	897,112

See accompanying notes.

Table of Contents

KOSMOS ENERGY LTD.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31,		
	2017	2016	2015
Operating activities			
Net loss	$(222,792)	$(283,780)	$(69,836)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depletion, depreciation and amortization	265,407	150,608	166,290
Deferred income taxes	9,505	(23,561)	110,786
Unsuccessful well costs	43,201	6,079	94,910
Change in fair value of derivatives	71,822	46,559	(210,957)
Cash settlements on derivatives, net (including $38.7 million, $188.0 million and $225.5 million on commodity hedges during 2017, 2016, and 2015)	25,888	188,895	224,741
Equity-based compensation	39,913	40,084	75,057
Gain on sale of assets	—	—	(24,651)
Loss on extinguishment of debt	—	—	165
Loss on equity method investment, net	6,252	—	—
Other	5,952	13,355	7,875
Changes in assets and liabilities:			
(Increase) decrease in receivables	29,365	(20,558)	2,209
(Increase) decrease in inventories	1,653	(4,107)	(29,855)
(Increase) decrease in prepaid expenses and other	(31,710)	17,557	512
Increase (decrease) in accounts payable	(94,434)	(75,487)	111,289
Increase (decrease) in accrued liabilities	86,595	(3,567)	(17,756)
Net cash provided by operating activities	236,617	52,077	440,779
Investing activities			
Oil and gas assets	(140,495)	(535,975)	(823,642)
Other property	(2,858)	(1,998)	(1,483)
Equity method investment	(231,280)	—	—
Proceeds on sale of assets	222,068	210	28,692
Net cash used in investing activities	(152,565)	(537,763)	(796,433)
Financing activities			
Borrowings under long-term debt	200,000	450,000	100,000
Payments on long-term debt	(250,000)	—	(200,000)
Net proceeds from issuance of senior secured notes	—	—	206,774
Purchase of treasury stock	(2,194)	(1,981)	(18,110)
Deferred financing costs	(67)	—	(9,030)
Net cash provided by (used in) financing activities	(52,261)	448,019	79,634
Net increase (decrease) in cash, cash equivalents and restricted cash	31,791	(37,667)	(276,020)
Cash, cash equivalents and restricted cash at beginning of period	273,195	310,862	586,882
Cash, cash equivalents and restricted cash at end of period	$304,986	$273,195	$310,862
Supplemental cash flow information			
Cash paid for:			
Interest	$55,381	$27,860	$33,315
Income taxes	$48,815	$13,997	$35,857

Non-cash activity:			
Conversion of joint interest billings receivable to long-term note receivable	$—	$9,814	$—
Contribution to equity method investment	$133,893	$—	$—
Dissolution of equity method investment	$(122,407)	$—	$—

See accompanying notes.

94

Table of Contents

KOSMOS ENERGY LTD.
Notes to Consolidated Financial Statements
1. Organization

Kosmos Energy Ltd. was incorporated pursuant to the laws of Bermuda in January 2011 to become a holding company for Kosmos Energy Holdings. Kosmos Energy Holdings is a privately held Cayman Islands company that was formed in March 2004. As a holding company, Kosmos Energy Ltd.'s management operations are conducted through a wholly owned subsidiary, Kosmos Energy, LLC. The terms “Kosmos,” the “Company,” “we,” “us,” “our,” “ours,” ar similar terms refer to Kosmos Energy Ltd. and its wholly owned subsidiaries, unless the context indicates otherwise. Kosmos is a leading independent oil and gas exploration and production company focused on frontier and emerging areas along the Atlantic Margins. Our assets include existing production and development projects offshore Ghana and Equatorial Guinea, large discoveries and significant further exploration potential offshore Mauritania and Senegal, as well as exploration licenses offshore Cote d'Ivoire, Equatorial Guinea, Morocco, Sao Tome and Principe, and Suriname. Kosmos is listed on the New York Stock Exchange (“NYSE”) and London Stock Exchange ("LSE") and is traded under the ticker symbol KOS.

We have one reportable segment, which is the exploration and production of oil and natural gas. Substantially all of our long lived assets and all of our product sales are related to production located offshore Ghana. We also have an equity method investment generating revenues with operations offshore Equatorial Guinea.

Table of Contents

2. Accounting Policies
Principles of Consolidation
The accompanying consolidated financial statements include the accounts of Kosmos Energy Ltd. and its wholly owned subsidiaries. They also include the Corporation's share of the undivided interest in certain assets, liabilities, revenues and expenses. Investments in corporate joint ventures, which we exercise significant influence over, are accounted for using the equity method of accounting. All intercompany transactions have been eliminated. Investments in companies that are partially owned by the Corporation are integral to the Corporation's operations. The other parties, who also have an equity interest in these companies, are independent third parties that share in the business results according to their ownership. Kosmos does not invest in these companies in order to remove liabilities from its balance sheet.

Use of Estimates
The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets and liabilities. Actual results could differ from these estimates.
Reclassifications
Certain prior period amounts have been reclassified to conform with the current year presentation. Such reclassifications had no material impact on our reported net income (loss), current assets, total assets, current liabilities, total liabilities, shareholders' equity or cash flows, except as disclosed related to the adoption of recent accounting pronouncements.
Cash, Cash Equivalents and Restricted Cash

	December 31,		
	2017	2016	2015
	(In thousands)		
Cash and cash equivalents	$233,412	$194,057	$275,004
Restricted cash - current	56,380	24,506	28,533
Restricted cash - long-term	15,194	54,632	7,325
Total cash, cash equivalents and restricted cash shown in the consolidated statements of cash flows	$304,986	$273,195	$310,862

Cash and cash equivalents includes demand deposits and funds invested in highly liquid instruments with original maturities of three months or less at the date of purchase.
In accordance with our commercial debt facility (the "Facility"), we were required to maintain a restricted cash balance that is sufficient to meet the payment of interest and fees for the next six month period on the 7.875% Senior Secured Notes due 2021 ("Senior Notes") plus the Corporate Revolver or the Facility, whichever is greater. As of December 31, 2017 and 2016, we had $24.8 million and $24.5 million, respectively, in current restricted cash to meet this requirement.
In addition, in accordance with certain of our petroleum contracts, we have posted letters of credit related to performance guarantees for our minimum work obligations. These letters of credit are cash collateralized in accounts held by us and as such are classified as restricted cash. Upon completion of the minimum work obligations and/or entering into the next phase of the petroleum contract, the requirement to post the existing letters of credit will be satisfied and the cash collateral will be released. However, additional letters of credit may be required should we choose to move into the next phase of certain of our petroleum contracts. As of December 31, 2017 and 2016, we had $31.6 million and zero, respectively, of current restricted cash and $15.2 million and $54.6 million, respectively, of long term restricted cash used to cash collateralize performance guarantees related to our petroleum contracts.
Receivables
Our receivables consist of joint interest billings, oil sales and other receivables. For our oil sales receivable, we require a letter of credit to be posted to secure the outstanding receivable. Receivables from joint interest owners are stated at amounts due, net of any allowances for doubtful accounts. We determine our allowance by considering the length of

time past due, future net revenues of the debtor’s ownership interest in oil and natural gas properties we operate, and the owner’s ability to pay its

Table of Contents

obligation, among other things. We had an allowance for doubtful accounts of zero and $0.6 million in current joint interest billings receivables as of December 31, 2017 and 2016, respectively.

Inventories

Inventories consisted of $63.5 million and $68.1 million of materials and supplies and $8.4 million and $6.3 million of hydrocarbons as of December 31, 2017 and 2016, respectively. The Company's materials and supplies inventory primarily consists of casing and wellheads and is stated at the lower of cost, using the weighted average cost method, or net realizable value. We recorded write downs of $0.9 million, $14.9 million and nil during the years ended December 31, 2017, 2016 and 2015 for materials and supplies inventories as other expenses, net in the consolidated statements of operations and other in the consolidated statements of cash flows.

Hydrocarbon inventory is carried at the lower of cost, using the weighted average cost method, or net realizable value. Hydrocarbon inventory costs include expenditures and other charges incurred in bringing the inventory to its existing condition. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory costs.

Exploration and Development Costs

The Company follows the successful efforts method of accounting for its oil and gas properties. Acquisition costs for proved and unproved properties are capitalized when incurred. Costs of unproved properties are transferred to proved properties when a determination that proved reserves have been found. Exploration costs, including geological and geophysical costs and costs of carrying unproved properties, are expensed as incurred. Exploratory drilling costs are capitalized when incurred. If exploratory wells are determined to be commercially unsuccessful or dry holes, the applicable costs are expensed and recorded in exploration expense on the consolidated statement of operations. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized. Costs incurred to operate and maintain wells and equipment and to lift oil and natural gas to the surface are expensed as oil and gas production expense.

The Company evaluates unproved property periodically for impairment. The impairment assessment considers results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. If the quantity of potential future reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, the Company will recognize an impairment loss at that time.

Depletion, Depreciation and Amortization

Proved properties and support equipment and facilities are depleted using the unit of production method based on estimated proved oil and natural gas reserves. Capitalized exploratory drilling costs that result in a discovery of proved reserves and development costs are amortized using the unit of production method based on estimated proved developed oil and natural gas reserves for the related field.

Depreciation and amortization of other property is computed using the straight-line method over the assets' estimated useful lives (not to exceed the lease term for leasehold improvements), ranging from one to eight years.

	Years Depreciated
Leasehold improvements	1 to 8
Office furniture, fixtures and computer equipment	3 to 7
Vehicles	5

Amortization of deferred financing costs is computed using the straight line method over the life of the related debt.

Capitalized Interest

Interest costs from external borrowings are capitalized on major projects with an expected construction period of one year or longer. 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.

Asset Retirement Obligations

The Company accounts for asset retirement obligations as required by ASC 410—Asset Retirement and Environmental Obligations. Under these standards, the fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. If a reasonable estimate of fair value cannot be made in the

97

Table of Contents

period the asset retirement obligation is incurred, the liability is recognized when a reasonable estimate of fair value can be made. If a tangible long lived asset with an existing asset retirement obligation is acquired, a liability for that obligation is recognized at the asset's acquisition date. In addition, a liability for the fair value of a conditional asset retirement obligation is recorded if the fair value of the liability can be reasonably estimated. We capitalize the asset retirement costs by increasing the carrying amount of the related long lived asset by the same amount as the liability. We record increases in the discounted abandonment liability resulting from the passage of time in depletion and depreciation in the consolidated statement of operations.

Impairment of Long lived Assets

The Company reviews its long lived assets for impairment when changes in circumstances indicate that the carrying amount of an asset may not be recoverable, or at least annually. ASC 360—Property, Plant and Equipment requires an impairment loss to be recognized if the carrying amount of a long lived asset is not recoverable and exceeds its fair value. The carrying amount of a long lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. That assessment shall be based on the carrying amount of the asset at the date it is tested for recoverability, whether in use or under development. An impairment loss shall be measured as the amount by which the carrying amount of a long lived asset exceeds its fair value. Assets to be disposed of and assets not expected to provide any future service potential to the Company are recorded at the lower of carrying amount or fair value less cost to sell.

We believe the assumptions used in our undiscounted cash flow analysis to test for impairment are appropriate and result in a reasonable estimate of future cash flows. The undiscounted cash flows from the analysis exceeded the carrying amount of our long-lived assets. The most significant assumptions are the pricing and production estimates used in undiscounted cash flow analysis. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the evaluation. In order to evaluate the sensitivity of the assumptions, we assumed a hypothetical reduction in our production profile which still showed no impairment. If we experience declines in oil pricing, increases in our estimated future expenditures or a decrease in our estimated production profile our long-lived assets could be at risk for impairment.

Derivative Instruments and Hedging Activities

We utilize oil derivative contracts to mitigate our exposure to commodity price risk associated with our anticipated future oil production. These derivative contracts consist of collars, put options, call options and swaps. We also use interest rate derivative contracts to mitigate our exposure to interest rate fluctuations related to our long term debt. Our derivative financial instruments are recorded on the balance sheet as either assets or liabilities and are measured at fair value. We do not apply hedge accounting to our derivative contracts. As of December 31, 2016 all instruments previously designated as hedges have settled and there is no balance remaining in AOCI. See Note 9—Derivative Financial Instruments.

Estimates of Proved Oil and Natural Gas Reserves

Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and assessment of impairment of our oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. As additional proved reserves are discovered, reserve quantities and future cash flows will be estimated by independent petroleum consultants and prepared in accordance with guidelines established by the Securities and Exchange Commission ("SEC") and the Financial Accounting Standards Board ("FASB"). The accuracy of these reserve estimates is a function of:

- the engineering and geological interpretation of available data;
- estimates of the amount and timing of future operating cost, production taxes, development cost and workover cost;
- the accuracy of various mandated economic assumptions; and
- the judgments of the persons preparing the estimates.

Revenue Recognition

We use the sales method of accounting for oil and gas revenues. Under this method, 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. These differences result in a condition known in the industry as a production imbalance. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves on such property. As of December 31, 2017 and 2016, we had no oil and gas imbalances recorded in our consolidated financial statements.

Our oil and gas revenues are based on provisional price contracts which contain an embedded derivative that is required to be separated from the host contract for accounting purposes. The host contract is the receivable from oil sales at the spot price on the date of sale. The embedded derivative, which is not designated as a hedge, is marked to market through oil and gas revenue each period until the final settlement occurs, which generally is limited to the month after the sale.

Equity based Compensation

For equity based compensation awards, compensation expense is recognized in the Company’s financial statements over the awards’ vesting periods based on their grant date fair value. The Company utilizes (i) the closing stock price on the date of grant to determine the fair value of service vesting restricted stock awards and restricted stock units and (ii) a Monte Carlo simulation to determine the fair value of restricted stock awards and restricted stock units with a combination of market and service vesting criteria. Forfeitures are recognized in the period in which they occur.

Treasury Stock

We record treasury stock purchases at cost. Our treasury stock purchases are from our employees that surrendered shares to the Company to satisfy their statutory tax withholding requirements and are not part of a formal stock repurchase plan. The remainder of our treasury stock is forfeited restricted stock awards granted under our long term incentive plan.

Income Taxes

The Company accounts for income taxes as required by ASC 740—Income Taxes. Under this method, deferred income taxes are determined based on the difference between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts expected to be realized. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary.

We recognize tax benefits from uncertain tax positions only if it is more likely than not that the tax position will be sustained upon examination by the tax authorities, based on the technical merits of the position. Accordingly, we measure tax benefits from such positions based on the most likely outcome to be realized.

FASB Staff Accounting Bulletin 118 (SAB 118) was issued in January 2018 to address situations where certain aspects of the Tax Reform Act are unclear at issuance of a registrant’s financial statements for the reporting period in which the Tax Reform Act became law. SAB 118 allows us to record provisional amounts during a one year measurement period. We are analyzing certain aspects of the Tax Reform Act which could potentially affect the measurement of deferred tax balances or potentially give rise to new deferred tax amounts.

Foreign Currency Translation

The U.S. dollar is the functional currency for all of the Company’s material foreign operations. Foreign currency transaction gains and losses and adjustments resulting from translating monetary assets and liabilities denominated in foreign currencies are included in other expenses. Cash balances held in foreign currencies are not significant, and as such, the effect of exchange rate changes is not material to any reporting period.

Concentration of Credit Risk

Our revenue can be materially affected by current economic conditions and the price of oil. However, based on the current demand for crude oil and the fact that alternative purchasers are readily available, we believe that the loss of our marketing agent and/or any of the purchasers identified by our marketing agent would not have a long term material adverse effect on our financial position or results of operations.

Recent Accounting Standards

Recently Adopted

In January 2017, the FASB issued ASU 2017-1, "Business Combinations (Topic 805): Clarifying the Definition of a Business." ASU 2017-1 clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether those transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The amendments in this ASU are effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years with early adoption permitted. Effective October 1, 2017, we early adopted ASU

2017-1 in connection with our accounting treatment of the Equatorial Guinea acquisition during the fourth quarter of 2017.

99

Table of Contents

Not Yet Adopted

In May 2014, the FASB issued ASU 2014-9, "Revenue from Contracts with Customers (Topic 606)," which supersedes the revenue recognition requirements in ASC Topic 605, "Revenue Recognition," and most industry-specific guidance. ASU 2014-9 is based on the principle that revenue is recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-9 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. ASU 2014-9 applies to all contracts with customers except those that are within the scope of other topics in the FASB ASC. The new guidance is effective for annual reporting periods beginning after December 15, 2017 for public companies. Early adoption is not permitted. Entities have the option of using either a full retrospective or modified retrospective approach to adopt ASU 2014-9. The Company completed its assessment of the new accounting standard and does not expect the adoption of this standard to have a material impact to our revenue recognition based on our existing contracts with customers. We will adopt the new standard during the first quarter of 2018 using the modified retrospective approach and there will be no impact to our previously recorded revenue under the new standard.

In February 2016, the FASB issued ASU 2016-2, “Leases (Topic 842).” ASU 2016-2 was issued to increase transparency and comparability across organizations by recognizing substantially all leases on the balance sheet through the concept of right-of-use lease assets and liabilities. Under current accounting guidance, lessees do not recognize lease assets or liabilities for leases classified as operating leases. The ASU is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years with early adoption permitted. The new leasing standard requires the modified retrospective adoption method. The Company is in the process of evaluating the impact of this accounting standard on its consolidated financial statements.

In October 2016, the FASB issued ASU 2016-16, “Intra-Entity Transfers of Assets Other Than Inventory.” ASU 2016-16 requires the company to recognize income tax consequences, if any, on intercompany asset transfers, other than inventory, when the transfer occurs. The ASU is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years with early adoption permitted. The Company does not expect the adoption of this standard to have a material impact on its consolidated financial statements.

3. Acquisitions and Divestitures

2017 Transactions

In December 2016, we announced transactions with affiliates of BP p.l.c. (‘‘BP’’) in Mauritania and Senegal following a competitive farm-out process for our interests in our blocks offshore Mauritania and Senegal. The Mauritania and Senegal transactions closed in January 2017 and February 2017, respectively. In Mauritania, BP acquired a 62% participating interest in our four Mauritania licenses (C6, C8, C12 and C13). In Senegal, BP acquired a 49.99% interest in KBSL, our majority owned affiliate company which held a 60% participating interest in the Cayar Offshore Profond and Saint Louis Offshore Profond blocks (the "Senegal Blocks") offshore Senegal. Previously we indicated that KBSL would hold a 65% participating interest upon the completion of our exercise in December 2016 of an option to increase our equity in each contract area by 5% in exchange for carrying Timis Corporation Limited’s (“Timis”) paying interest share of a third well in either contract area, subject to a maximum gross well cost of $120.0 million. However, we agreed to withdraw the exercise of this call option upon completion of an agreement between BP and Timis by which BP acquired Timis’ entire 30% participating interest in the Senegal Blocks. The transaction between BP and Timis was completed and KBSL’s participating interest in these blocks remained at 60%. In consideration for these transactions, Kosmos received $162 million in cash up front during the first quarter of 2017 and will receive $228 million exploration and appraisal carry (increased from $221 million upon completion of the transfer of a 30% working interest to BP Senegal Investments Limited), up to $533 million in a development carry and variable consideration up to $2 per barrel for up to 1 billion barrels of liquids, structured as a production royalty, subject to future liquids discovery and prevailing oil prices. The effective date of these transactions was July 1, 2016, with BP paying interim costs from the effective date to the closing dates. We reduced our unproved property balance by $221.9 million for the consideration received as a result of these transactions including the upfront cash and interim costs from the transaction date to the effective date. See Note 7—Equity Method Investments for further discussion of our investment in KBSL.

In November 2015, we entered into a line of credit agreement with Timis, whereby Timis had the right to draw up to $30.0 million on the line of credit to offset its joint interest billings arising from costs under the Senegal Blocks petroleum agreements. The line of credit agreement was terminated in April 2017 when Timis entered into an agreement with BP to acquire Timis' 30% participating interest in the Senegal Blocks. As a result of the termination of this credit agreement, Kosmos received $16 million in August 2017 representing payment in full of outstanding amounts drawn on the line of credit.

Table of Contents

In September 2017, we closed a farm-in agreement with Tullow Mauritania Limited, a subsidiary of Tullow Oil plc (“Tullow”), to acquire a 15% non-operated participating interest in Block C18 offshore Mauritania. Based on the terms of the agreement, we will reimburse a portion of past and interim period costs and partially carry future costs.

In the fourth quarter of 2017, through a joint venture with an affiliate of Trident Energy ("Trident"), we acquired all of the equity interest of Hess International Petroleum Inc., a subsidiary of Hess Corporation ("Hess"), which holds an 85% paying interest (80.75% revenue interest) in the Ceiba Field and Okume Complex assets. Under the terms of the agreement, Kosmos and Trident each own 50% of Hess International Petroleum Inc. Hess International Petroleum Inc. was subsequently renamed Kosmos-Trident International Petroleum Inc. ("KTIPI"). Kosmos is primarily responsible for exploration and subsurface evaluation while Trident is primarily responsible for production operations and optimization. The gross acquisition price was $650 million effective as of January 1, 2017. After post closing entries Kosmos paid net cash of approximately $231 million, with a combination of cash on hand and availability under the Facility. The transaction is accounted for as an equity method investment.

In October 2017, we entered into petroleum contracts covering Blocks EG-21, S, and W with the Republic of Equatorial Guinea, subject to ratification by the President of Equatorial Guinea. We presently have an 80% participating interest and are the operator in all three blocks, but pursuant to an agreement with Trident, we expect to assign a 40% participating interest in the blocks to an affiliate of Trident after ratification. The Equatorial Guinean national oil company, Guinea Equatorial De Petroleos ("GEPetrol"), currently has a 20% carried participating interest during the exploration period. Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest. The petroleum contracts cover approximately 6,000 square kilometers, with a first exploration period of five years from the date of notification of ratification by the President of Equatorial Guinea. The first exploration period consists of two sub-periods of three and two years, respectively. The first exploration sub-period work program includes an approximately 6,000 square kilometer 3D seismic acquisition requirement across the three blocks. Upon ratification and the assignment of a 40% interest to the Trident affiliate noted above, interests in these three blocks will be 40% Kosmos, 40% Trident and 20% GEPetrol.

In December 2017, as part of our Alliance with BP, we entered into petroleum contracts covering Blocks CI-526, CI-602, CI-603, CI-707 and CI-708 with the Government of Cote d'Ivoire. We have a 45% participating interest and are the operator in all five blocks. BP has a 45% participating interest in the blocks and the Cote d'Ivoire national oil company, PETROCI Holding ("PETROCI"), currently has a 10% carried interest. The petroleum contracts cover approximately 17,000 square kilometers, with a first exploration period of three years. The first exploration period work program includes a 12,000 square kilometer 3D seismic acquisition across the five blocks.

2016 Transactions

In January and February 2016, we closed farm-in agreements with Equator Exploration Limited (“Equator”), an affiliate of Oando Energy Resources, for Block 5 and Block 12 offshore Sao Tome and Principe. As a result of subsequent farm-outs we currently have a 45% participating interest and operatorship in each block. The national petroleum agency, ANP STP, has a 15% and 12.5% carried interest in Block 5 and Block 12, respectively.

In April 2016, we closed a farm-out agreement with Hess Suriname Exploration Limited, a wholly-owned subsidiary of the Hess Corporation (“Hess”), covering the Block 42 contract area offshore Suriname. Under the terms of the agreement, Hess acquired a one-third non-operated interest in Block 42 from both Chevron and Kosmos. As part of the agreement, Hess is funding the cost of acquiring and processing a 6,500 square kilometer 3D seismic survey, subject to a maximum spend. Additionally, Hess will disproportionately fund a portion of the first exploration well in the Block 42 contract area, subject to a maximum spend, contingent upon the partnership entering the next phase of the exploration period. The new participating interests are one-third to each of Kosmos, Chevron and Hess, respectively. Kosmos remains the operator. Staatsolie Maatschappij Suriname N.V. (“Staatsolie”), Suriname’s national oil company, has the option to back into the contract with an interest of not more than 10% upon approval of a development plan.

In May 2016, Kosmos and Capricorn Exploration and Development Company Limited, a wholly owned subsidiary of Cairn Energy PLC (“Cairn”) executed a petroleum agreement with the Office National des Hydrocarbures et des Mines ("ONHYM"), the national oil company of the Kingdom of Morocco, for the Boujdour Maritime block. The Boujdour Maritime petroleum agreement largely replaces the acreage covered by the Cap Boujdour petroleum agreement which expired in March 2016. Under the terms of the petroleum agreement, Kosmos is the operator of the Boujdour Maritime block and has a 55% participating interest, Cairn has a 20% participating interest, and ONHYM holds a 25% carried interest in the block through the exploration period. In November 2017, we provided to our co-venturers a notice of withdrawal from the the Boujdour Maritime block offshore Western Sahara and transferred its participating interest and operatorship to ONHYM. Certain transition services are being provided to ONHYM as part of the handover of operatorship. In order to complete our obligations under the petroleum contract, we will continue to fund the remainder of the seismic program.

Table of Contents

In September 2016, we entered into an agreement by which BP agreed to pay Kosmos $30 million in lieu of drilling an exploration well and assigned its 45% participating interest in the Essaouira Offshore Block back to us, and the Moroccan government issued joint ministerial orders approving the assignment in October 2016, making it effective. After giving effect to the assignment, our participating interest is 75% in the Essaouria Offshore block and we remain the operator. The $30 million payment was received from BP in January 2017.

In October 2016, we entered into a petroleum contract covering Block C6 with the Islamic Republic of Mauritania. As a result of a subsequent farm-out we have a 28% participating interest and provide technical exploration services to BP, the operator. The Mauritanian national oil company, Societe Mauritanienne des Hydrocarbures et de Patrimoine Minier ("SMHPM"), currently has a 10% carried participating interest during the exploration period. Block C6 currently comprises approximately 1.1 million acres (4,300 square kilometers), with a first exploration period of four years from the effective date (October 28, 2016). The first exploration phase includes a 2,000 square kilometer 3D seismic requirement.

In December 2016, Kosmos closed a farm-out agreement with a subsidiary of Galp Energia SGPS S.A. ("Galp") to farm-out a 20% non-operated stake of the Company's interest in Blocks 5, 11, and 12 offshore Sao Tome and Principe. Based on the terms of the agreement, Galp paid a proportionate share of Kosmos' past costs in the form of a partial carry on the 3D seismic survey which was completed in August 2017.

2015 Transactions

In March 2015, we closed a farm-in agreement with Repsol Exploracion, S.A. ("Repsol"), acquiring a non-operated interest in the Camarao, Ameijoa, Mexilhao and Ostra blocks in the Peniche Basin offshore Portugal. As part of the agreement, we reimbursed a portion of Repsol's previously incurred exploration costs, as well as partially carried Repsol's share of the costs of a planned 3D seismic program. After giving effect to the farm-in agreement, our participating interest was 31% in each of the blocks. In January 2017, we provided to our co-venturers a notice of withdrawal from the Ameijoa, Camarao, Mexilhao and Ostra Blocks offshore Portugal.

In March 2015, we closed a farm out agreement with Chevron Corporation ("Chevron") covering the C8, C12 and C13 petroleum contracts offshore Mauritania. As partial consideration for the farm-out, Chevron paid a disproportionate share of the costs of one exploration well, the Marsouin-1 exploration well, as well as its proportionate share of certain previously incurred exploration costs. The final allocation resulted in sales proceeds of $28.7 million, which exceeded our book basis in the assets, resulting in a $24.7 million gain on the transaction. As a further component of the consideration for the farm-out, Chevron was required to make an election by February 1, 2016, to either farm-in to the Tortue-1 exploration well by paying a disproportionate share of the costs incurred in drilling of the well or, alternatively elect to not farm-in to the Tortue-1 exploration well and pay a disproportionate share of the costs of a second contingent exploration or appraisal well in the contract areas, subject to maximum expenditure caps. Chevron failed to make this mandatory election by the required date. Consequently, pursuant to the terms of the farm-out agreement, Chevron has withdrawn from our Mauritania blocks. Chevron's 30% non-operated participating interest was reassigned to us.

In September 2015, we notified the government of Ireland and our partners that we are withdrawing from all of our blocks offshore Ireland. These blocks were acquired during 2013.

In October 2015, we closed a sale and purchase agreement with ERHC Energy EEZ, LDA, whereby we acquired an 85% participating interest and operatorship in Block 11 offshore Sao Tome and Principe. The National Petroleum Agency, Agencia Nacional Do Petroleo De Sao Tome E Príncipe ("ANP STP"), has a 15% carried interest.

In November 2015, we closed a farm-in agreement with Galp Energia Sao Tome E Principe, Unipessoal, LDA ("Galp"), a wholly owned subsidiary of Petrogal, S.A. to acquire a 45% non-operated participating interest in Block 6 offshore Sao Tome and Principe.

Table of Contents

4. Joint Interest Billings

The Company's joint interest billings consist of receivables from partners with interests in common oil and gas properties operated by the us. Joint interest billings are classified on the face of the consolidated balance sheets as current and long-term receivables based on when collection is expected to occur.

In 2014, the Ghana National Petroleum Corporation ("GNPC") notified us and our block partners of its request for the contractor group to pay GNPC's 5% share of the Tweneboa, Enyenra and Ntomme ("TEN") development costs. The block partners will be reimbursed for such costs plus interest out of a portion of GNPC's TEN production revenues. As of December 31, 2017 and 2016, the current portion of the joint interest billing receivables due from GNPC for the TEN fields development costs were $15.2 million and zero, respectively, and the long-term portion is $31.6 million and $44.0 million.

5. Property and Equipment

Property and equipment is stated at cost and consisted of the following:

	December 31,	
	2017	2016
	(In thousands)	
Oil and gas properties:		
Proved properties	$1,653,616	$1,385,331
Unproved properties	465,109	919,056
Support equipment and facilities	1,427,054	1,386,448
Total oil and gas properties	3,545,779	3,690,835
Accumulated depletion	(1,234,806)	(989,946)
Oil and gas properties, net	2,310,973	2,700,889
Other property	39,405	37,186
Accumulated depreciation	(32,550)	(29,183)
Other property, net	6,855	8,003
Property and equipment, net	$2,317,828	$2,708,892

We recorded depletion expense of $244.9 million, $131.5 million and $146.6 million for the years ended December 31, 2017, 2016 and 2015, respectively.

6. Suspended Well Costs

The Company capitalizes exploratory well costs as unproved properties within oil and gas properties until a determination is made that the well has either found proved reserves or is impaired. If proved reserves are found, the capitalized exploratory well costs are reclassified to proved properties. Well costs are charged to exploration expense if the exploratory well is determined to be impaired.

The following table reflects the Company's capitalized exploratory well costs on completed wells as of and during the years ended December 31, 2017, 2016 and 2015. The table excludes $43.2 million, $2.4 million and $70.3 million in costs that were capitalized and subsequently expensed during the same year for the years ended December 31, 2017, 2016 and 2015, respectively. During 2017, the exploratory well costs associated with the Mahogany and Teak fields were reclassified to proved property as they were unitized into the Jubilee Unit as part of the Greater Jubilee Full Field Development Plan.

	Years Ended December 31,		
	2017	2016	2015
	(In thousands)		
Beginning balance	$734,463	$426,881	$226,714
Additions to capitalized exploratory well costs pending the determination of proved reserves	69,567	307,582	223,542
Reclassification due to unitization of Mahogany and Teak discoveries	(176,881)	—	—
Divestitures(1)	(206,400)	—	—
Contribution of oil and gas property to equity method investment	(131,764)	—	—
Dissolution of equity method investment	121,128	—	—
Capitalized exploratory well costs charged to expense	—	—	(23,375)
Ending balance	$410,113	$734,463	$426,881

(1) Represents the reduction in basis of suspended well costs associated with the Mauritania and Senegal transactions with BP.

The following table provides aging of capitalized exploratory well costs based on the date drilling was completed and the number of projects for which exploratory well costs have been capitalized for more than one year since the completion of drilling:

	Years Ended December 31,		
	2017	2016	2015
	(In thousands, except well counts)		
Exploratory well costs capitalized for a period of one year or less	$67,159	$279,809	$199,486
Exploratory well costs capitalized for a period of one to two years	291,252	244,804	17,702
Exploratory well costs capitalized for a period of three to six years	51,702	209,850	209,693
Ending balance	$410,113	$734,463	$426,881
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	5	5	3

As of December 31, 2017, the projects with exploratory well costs capitalized for more than one year since the completion of drilling are related to the Akasa discovery in the West Cape Three Points (“WCTP”) Block and the Wawa discovery in the DT Block, which are located offshore Ghana, the Greater Tortue discovery which crosses the Mauritania and Senegal maritime border, the BirAllah discovery (formerly known as the Marsouin discovery) in Block C8 offshore Mauritania and the Teranga discovery in the Cayar Offshore Profond block offshore Senegal.

Akasa Discovery — We are currently in discussions with the government of Ghana regarding additional technical studies and evaluation that we want to conduct before we are able to make a determination regarding commerciality of the discovery. If we determine the discovery to be commercial, a declaration of commerciality would be provided and a PoD would be prepared and submitted to Ghana’s Ministry of Energy, as required under the WCTP petroleum contract.

Wawa Discovery — In February 2016, we requested the Ghana Ministry of Energy to approve the enlargement of the areal extent of the TEN fields and production area to capture the resource accumulation located in the Wawa Discovery Area for a potential future integrated development with the TEN fields. In April 2016, the Ghana Ministry of Energy approved our request to enlarge the TEN development and production area subject to continued subsurface and development concept evaluation, along with the requirement to integrate the Wawa Discovery into the TEN PoD. We are currently in discussions with the Ministry of Energy with respect to conducting further subsurface and development concept evaluation.

Greater Tortue Discovery — In May 2015, we completed the Tortue-1 exploration well in Block C8 offshore Mauritania which encountered hydrocarbon pay. Two additional wells have been drilled in the Greater Tortue Discovery area, Ahmeyim-2 in Mauritania and Guembeul-1 in Senegal. We completed a drill stem test on the Tortue 1 well in August 2017, which confirmed the production capabilities of the Greater Tortue Discovery. Data acquired from the drill stem test is being used to further optimize field development and to refine process design parameters critical to the Front

End Engineering Design (FEED) process. Following additional evaluation, a decision regarding commerciality will be made.

Table of Contents

BirAllah Discovery — In November 2015, we completed the Marsouin-1 exploration well (renamed BirAllah) in the northern part of Block C8 offshore Mauritania which encountered hydrocarbon pay. Following additional evaluation, a decision regarding commerciality will be made.
Teranga Discovery — In May 2016, we completed the Teranga-1 exploration well in the Cayar Offshore Profond block offshore Senegal which encountered hydrocarbon pay. Following additional evaluation, a decision regarding commerciality will be made.

7. Equity Method Investments
Kosmos BP Senegal Limited

As part of our transaction in Senegal with BP, our petroleum contracts in Senegal were contributed to KBSL, a corporate joint venture in which we owned a 50.01% interest. The objective of this transaction was to accelerate the development of discovered gas resources, ensure the execution of an appropriately sized exploration program and reduce the Company's capital spending requirements for exploration and development over the near to medium term.

In October 2017, upon approval, KBSL transferred a 30% working interest in the Senegal Blocks to BP Senegal Investments Limited in exchange for their outstanding shares of KBSL. As a result, KBSL became a wholly-owned subsidiary of Kosmos, and will no longer be accounted for under the equity method of accounting. After the transfer, KBSL has a 30% working interest in the Senegal Blocks.

Prior to the acquisition of the remaining outstanding shares of KBSL in October 2017, our investment in KBSL qualified for the equity method of accounting. Our initial contribution to KBSL was $133.9 million, which was recorded at our carrying costs. Our share of the KBSL operations during the period it was accounted for as an equity method investment is reflected in our consolidated statements of operations as loss on equity method investments, net. During the twelve months ended December 31, 2017, we recorded an $11.5 million loss on equity method investment associated with KBSL.

Equatorial Guinea

As part of our acquisition of KTIPI, a corporate joint venture in which we own a 50% interest, we acquired the petroleum contract for Block G offshore Equatorial Guinea. The objective of this transaction was to acquire the Ceiba field and Okume complex with the intent to optimize production and increase reserves. Below is a summary of financial information for KTIPI.

	December 31, 2017 (In thousands)
Assets	
Total current assets	$ 179,070
Property and equipment, net	345,611
Other assets	567
Total assets	$ 525,248
Liabilities and shareholders' equity	
Total current liabilities	$ 106,769
Total long term liabilities	565,591
Shareholders' equity:	
Total shareholders' equity	(147,112)

Total liabilities and shareholders' equity	$ 525,248

105

Table of Contents

	Period November 28, 2017 through December 31, 2017
Revenues and other income:	
Oil and gas revenue	$ 54,615
Other income	294
Total revenues and other income	54,909
Costs and expenses:	
Oil and gas production	15,509
Depletion and depreciation	10,738
Other expenses, net	(19)
Total costs and expenses	26,228
Income before income taxes	28,681
Income tax expense	6,588
Net income	$ 22,093
Kosmos' share of net income	$ 11,046
Basis difference amortization(1)	5,812
Equity in earnings - KTIPI	$ 5,234

(1) The basis difference, which is associated with oil and gas properties and subject to amortization, has been allocated to the Ceiba Field and Okume Complex. We amortize the basis difference using the unit-of-production method.

When evaluating our equity method investments for impairment, we review our ability to recover the carrying amount of such investments or the entity's ability to sustain earnings that justify its carrying amount. As of December 31, 2017, we determined that we had the ability to recover the carrying amount of our equity method investment in KTIPI. As such, no impairment has been recorded.

8. Debt

	December 31, 2017	December 31, 2016
	(In thousands)	
Outstanding debt principal balances:		
Facility	$ 800,000	$ 850,000
Senior Notes	525,000	525,000
Total	1,325,000	1,375,000
Unamortized deferred financing costs and discounts(1)	(42,203)	(53,126)
Long-term debt, net	$ 1,282,797	$ 1,321,874

(1) Includes $23.6 million and $30.3 million of unamortized deferred financing costs related to the Facility and $18.6 million and $22.8 million of unamortized deferred financing costs and discounts related to the Senior Notes as of December 31, 2017 and December 31, 2016, respectively.

Facility

In March 2017, following the lender's semi-annual redetermination, the available borrowing base under our Facility was $1.3 billion (effective April 1, 2017). In August 2017, following the lender's waiver of the September 30, 2017 semi-annual

Table of Contents

redetermination, the available borrowing base under our Facility remained at $1.3 billion. The borrowing base calculation included value related to the Jubilee and TEN fields.

As of December 31, 2017, borrowings under the Facility totaled $800.0 million including $200 million drawn for the KTIPI investment, and the undrawn availability under the Facility was $500.8 million. Interest is the aggregate of the applicable margin (3.25% to 4.50%, depending on the length of time that has passed from the date the Facility was entered into) and LIBOR. Interest is payable on the last day of each interest period (and, if the interest period is longer than six months, on the dates falling at six-month intervals after the first day of the interest period). We pay commitment fees on the undrawn and unavailable portion of the total commitments, if any. Commitment fees were equal to 40% per annum of the then-applicable respective margin when a commitment is available for utilization and, equal to 20% per annum of the then-applicable respective margin when a commitment is not available for utilization. We recognize interest expense in accordance with ASC 835—Interest, which requires interest expense to be recognized using the effective interest method. We determined the effective interest rate based on the estimated level of borrowings under the Facility.

In February 2018, the Company amended and restated the Facility with a total commitment of $1.5 billion from a number of financial institutions with additional commitments up to $0.5 billion being available if the existing financial institutions increase their commitments or if commitments from new financial institutions are added. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities. As part of the debt refinancing in February 2018, the repayment of borrowings under the existing facility attributable to financial institutions that did not participate in the amended Facility was accounted for as an extinguishment of debt, and $5.7 million of existing unamortized debt issuance costs attributable to those participants were expensed in the first quarter of 2018. As of December 31, 2017, we have $23.6 million of unamortized issuance costs related to the Facility, which will be amortized over the remaining term of the Facility, excluding the $5.7 million expensed in the first quarter of 2018.

The Facility provides a revolving credit and letter of credit facility. The availability period for the revolving- credit facility, as amended in February 2018 expires one month prior to the final maturity date. The letter of credit facility expires on the final maturity date. The available facility amount is subject to borrowing base constraints and, beginning on March 31, 2022, outstanding borrowings will be constrained by an amortization schedule. The Facility has a final maturity date of March 31, 2025. As of December 31, 2017, we had no letters of credit issued under the Facility.

Kosmos has the right to cancel all the undrawn commitments under the amended and restated Facility. The amount of funds available to be borrowed under the Facility, also known as the borrowing base amount, is determined each year on March 31. The borrowing base amount is based on the sum of the net present values of net cash flows and relevant capital expenditures reduced by certain percentages as well as value attributable to certain assets' reserves and/or resources in Ghana and Equatorial Guinea.

If an event of default exists under the Facility, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Facility over certain assets held by our subsidiaries. The Facility contains customary cross default provisions.

We were in compliance with the financial covenants contained in the Facility as of the September 30, 2017 (the most recent assessment date).

Corporate Revolver

In November 2012, we secured a Corporate Revolver from a number of financial institutions which, as amended in June 2015, has an availability of $400.0 million. The Corporate Revolver is available for all subsidiaries for general corporate purposes and for oil and gas exploration; appraisal and development programs. As of December 31, 2017, we have $2.5 million of net deferred financing costs related to the Corporate Revolver, which will be amortized over the remaining term, which as amended expires in November 2018. These deferred financing costs are included in the Other assets section of the consolidated balance sheet.

As of December 31, 2017, there were no borrowings outstanding under the Corporate Revolver and the undrawn availability under the Corporate Revolver was $400.0 million.

Interest is the aggregate of the applicable margin (6.0%); LIBOR; and mandatory cost (if any, as defined in the Corporate Revolver). Interest is payable on the last day of each interest period (and, if the interest period is longer than six months, on the dates falling at six month intervals after the first day of the interest period). We pay commitment fees on the undrawn portion of the total commitments. Commitment fees, as amended in June 2015, for the lenders are equal to 30% per annum of the respective margin when a commitment is available for utilization.

Table of Contents

The Corporate Revolver, as amended in June 2015, expires on November 23, 2018. The available amount is not subject to borrowing base constraints. Kosmos has the right to cancel all the undrawn commitments under the Corporate Revolver. The Company is required to repay certain amounts due under the Corporate Revolver with sales of certain subsidiaries or sales of certain assets. If an event of default exists under the Corporate Revolver, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Corporate Revolver over certain assets held by us.

We were in compliance with the financial covenants contained in the Corporate Revolver as of September 30, 2017 (the most recent assessment date). The Corporate Revolver contains customary cross default provisions.

Revolving Letter of Credit Facility

In July 2013, we entered into a revolving letter of credit facility agreement ("LC Facility"). The size of the LC Facility is $75.0 million, as amended in July 2015, with additional commitments up to $50.0 million being available if the existing lender increases its commitment or if commitments from new financial institutions are added. The LC Facility provides that we maintain cash collateral in an amount equal to at least 75% of all outstanding letters of credit under the LC Facility, provided that during the period of any breach of certain financial covenants, the required cash collateral amount shall increase to 100%.

In July 2016, we amended and restated the LC Facility, extending the maturity date to July 2019. Other amendments included increasing the margin from 0.5% to 0.8% per annum on amounts outstanding, adding a commitment fee payable quarterly in arrears at an annual rate equal to 0.65% on the available commitment amount and providing for issuance fees to be payable to the lender per new issuance of a letter of credit. We may voluntarily cancel any commitments available under the LC Facility at any time. During the first quarter of 2017, the LC Facility size was increased to $115.0 million and in April 2017, we reduced the size of our LC Facility to $70 million. In February 2018, the LC Facility was increased to $73 million to facilitate the issuance of additional letters of credit. As of December 31, 2017, there were eight outstanding letters of credit totaling $60.3 million under the LC Facility. The LC Facility contains customary cross default provisions.

7.875% Senior Secured Notes due 2021

During August 2014, the Company issued $300.0 million of Senior Notes and received net proceeds of approximately $292.5 million after deducting discounts, commissions and deferred financing costs. The Company used the net proceeds to repay a portion of the outstanding indebtedness under the Facility and for general corporate purposes.

During April 2015, we issued an additional $225.0 million of Senior Notes and received net proceeds of $206.8 million after deducting discounts, commissions and other expenses. We used the net proceeds to repay a portion of the outstanding indebtedness under the Facility and for general corporate purposes. The additional $225.0 million of Senior Notes have identical terms to the initial $300.0 million Senior Notes, other than the date of issue, the initial price, the first interest payment date and the first date from which interest accrued.

The Senior Notes mature on August 1, 2021. Interest is payable semi-annually in arrears each February 1 and August 1 commencing on February 1, 2015 for the initial $300.0 million Senior Notes and August 1, 2015 for the additional $225.0 million Senior Notes. The Senior Notes are secured (subject to certain exceptions and permitted liens) by a first ranking fixed equitable charge on all shares held by us in our direct subsidiary, Kosmos Energy Holdings. The Senior Notes are currently guaranteed on a subordinated, unsecured basis by our existing restricted subsidiaries that guarantee the Facility and the Corporate Revolver, and, in certain circumstances, the Senior Notes will become guaranteed by certain of our other existing or future restricted subsidiaries (the "Guarantees").

Redemption and Repurchase. On or after August 1, 2017, the Company may redeem all or a part of the Senior Notes at the redemption prices (expressed as percentages of principal amount) set forth below plus accrued and unpaid interest:

Year	Percentage
On or after August 1, 2017, but before August 1, 2018	103.9 %

On or after August 1, 2018, but before August 1, 2019	102.0	%
On or after August 1, 2019 and thereafter	100.0	%

We may also redeem the Senior Notes in whole, but not in part, at any time if changes in tax laws impose certain withholding taxes on amounts payable on the Senior Notes at a price equal to the principal amount of the Senior Notes plus accrued interest and additional amounts, if any, as may be necessary so that the net amount received by each holder after any withholding or deduction on payments of the Senior Notes will not be less than the amount such holder would have received if such taxes had not been withheld or deducted.

Upon the occurrence of a change of control triggering event as defined under the Indenture, the Company will be required to make an offer to repurchase the Senior Notes at a repurchase price equal to 101% of the principal amount, plus accrued and unpaid interest to, but excluding, the date of repurchase.

If we sell assets, under certain circumstances outlined in the Indenture, we will be required to use the net proceeds to make an offer to purchase the Senior Notes at an offer price in cash in an amount equal to 100% of the principal amount of the Senior Notes, plus accrued and unpaid interest to, but excluding, the repurchase date.

Covenants. The Indenture restricts our ability and the ability of our restricted subsidiaries to, among other things: incur or guarantee additional indebtedness, create liens, pay dividends or make distributions in respect of capital stock, purchase or redeem capital stock, make investments or certain other restricted payments, sell assets, enter into agreements that restrict the ability of our subsidiaries to make dividends or other payments to us, enter into transactions with affiliates, or effect certain consolidations, mergers or amalgamations. These covenants are subject to a number of important qualifications and exceptions. Certain of these covenants will be terminated if the Senior Notes are assigned an investment grade rating by both Standard & Poor's Rating Services and Fitch Ratings Inc. and no default or event of default has occurred and is continuing.

Collateral. The Senior Notes are secured (subject to certain exceptions and permitted liens) by a first ranking fixed equitable charge on all currently outstanding shares, additional shares, dividends or other distributions paid in respect of such shares or any other property derived from such shares, in each case held by us in relation to the Company's direct subsidiary, Kosmos Energy Holdings, pursuant to the terms of the Charge over Shares of Kosmos Energy Holdings dated November 23, 2012, as amended and restated on March 14, 2014, between the Company and BNP Paribas as Security and Intercreditor Agent. The Senior Notes share pari passu in the benefit of such equitable charge based on the respective amounts of the obligations under the Indenture and the amount of obligations under the Corporate Revolver. The Guarantees are not secured.

At December 31, 2017, the estimated repayments of debt during the five years and thereafter are as follows:

	Payments Due by Year						
	Total	2018	2019	2020	2021	2022	Thereafter
	(In thousands)						
Principal debt repayments(1)	$1,325,000	$ —	$200,377	$404,971	$719,652	$ —	$ —

(1) Includes the scheduled principal maturities for the $525.0 million aggregate principal amount of Senior Notes issued in August 2014 and April 2015 and the Facility. The scheduled maturities of debt related to the Facility are based on the level of borrowings and the estimated future available borrowing base as of December 31, 2017. Any increases or decreases in the level of borrowings or increases or decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter. As of December 31, 2017, there were no borrowings under the Corporate Revolver.

Table of Contents

Interest and other financing costs, net

Interest and other financing costs, net incurred during the period comprised of the following:

	Years Ended December 31,		
	2017	2016	2015
	(In thousands)		
Interest expense	$92,687	$89,029	$74,897
Amortization—deferred financing costs	10,204	10,204	10,324
Loss on extinguishment of debt	—	—	165
Capitalized interest	(30,282)	(59,803)	(52,392)
Deferred interest	2,577	(581)	1,770
Interest income	(3,422)	(1,954)	(844)
Other, net	5,831	7,252	3,289
Interest and other financing costs, net	$77,595	$44,147	$37,209

9. Derivative Financial Instruments

We use financial derivative contracts to manage exposures to commodity price and interest rate fluctuations. We do not hold or issue derivative financial instruments for trading purposes.

We manage market and counterparty credit risk in accordance with our policies and guidelines. In accordance with these policies and guidelines, our management determines the appropriate timing and extent of derivative transactions. We have included an estimate of nonperformance risk in the fair value measurement of our derivative contracts as required by ASC 820—Fair Value Measurements and Disclosures.

Oil Derivative Contracts

The following table sets forth the volumes in barrels underlying the Company's outstanding oil derivative contracts and the weighted average Dated Brent prices per Bbl for those contracts as of December 31, 2017. Volumes are net of any offsetting derivative contracts entered into.

			Weighted Average Dated Brent Price per Bbl					
Term	Type of Contract	MBbl	Net Deferred Premium Payable	Swap	Sold Put	Floor	Ceiling	Call
2018:								
January — December	Swap with puts	2,000	$—	$54.32	$40.00	$—	$—	$ —
July — December	Swap with puts	2,000	—	57.96	45.00	—	—	—
January — June	Swaps	1,000	—	57.25	—	—	—	—
January — December	Three-way collars	2,913	0.74	—	41.57	56.57	65.90	—
January — December	Four-way collars	3,000	1.06	—	40.00	50.00	61.33	70.00
January — December	Sold calls(1)	2,000	—	—	—	—	65.00	—
2019:								
January — December	Three-way collars	6,500	$0.18	$—	$41.54	$51.54	$63.80	$ —
January — December	Two-way collars	2,000	1.62	—	—	55.00	65.00	—
January — December	Sold calls(1)	913	—	—	—	—	80.00	—

(1) Represents call option contracts sold to counterparties to enhance other derivative positions.

In January 2018, we entered into three-way costless collar contracts for 1.0 MMBbl from January 2019 through December 2019 with a sold put price of $45.00, a floor price of $55.00 per barrel and a ceiling price of $72.90 per barrel. The contracts are indexed to Dated Brent prices.

Table of Contents

In February 2018, we sold 2.0 MMBbl of put contracts from January 2019 through December 2019 with a strike of $47.50 per barrel. We used part of the proceeds to increase our upside exposure by purchasing 1.0 MMBbl of calls in the second half of 2018 with a strike of $70.00 per barrel. These contracts are indexed to Dated Brent prices and have a net deferred premium receivable of $3.1 million.

Interest Rate Derivative Contracts

The following table summarizes our capped interest rate swaps whereby we pay a fixed rate of interest if LIBOR is below the cap, and pay the market rate less the spread between the cap (sold call) and the fixed rate of interest if LIBOR is above the cap as of December 31, 2017:

			Weighted Average		
Term	Type of Contract	Floating Rate	Notional	Swap	Sold Call
			(In thousands)		
January 2018 — December 2018	Capped swap	1-month LIBOR	$200,000	1.23%	3.00%

See Note 10—Fair Value Measurements for additional information regarding the Company's derivative instruments.

The following tables disclose the Company's derivative instruments as of December 31, 2017 and 2016 and gain/(loss) from derivatives during the years ended December 31, 2017, 2016 and 2015.

		Estimated Fair Value Asset (Liability) December 31,	
Type of Contract	Balance Sheet Location	2017	2016
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative assets:			
Commodity(1)	Derivatives assets—current	$665	$31,698
Interest rate	Derivatives assets—current	1,017	—
Commodity(2)	Derivatives assets—long-term	39	3,226
Interest rate	Derivatives assets—long-term	—	582
Derivative liabilities:			
Commodity(3)	Derivatives liabilities—current	(67,531)	(19,163)
Interest rate	Derivatives liabilities—current	—	(529)
Commodity(4)	Derivatives liabilities—long-term	(30,209)	(14,123)
Total derivatives not designated as hedging instruments		$(96,019)	$1,691

(1) Includes net deferred premiums receivable of $0.8 million and net deferred premiums payable of $3.9 million related to commodity derivative contracts as of December 31, 2017 and 2016, respectively.

(2) Includes net deferred premiums receivable of $0.1 million and net deferred premiums payable of $2.5 million related to commodity derivative contracts as of December 31, 2017 and 2016, respectively.

(3) Includes zero and $30.9 thousand as of December 31, 2017 and December 31, 2016, respectively which represents our provisional oil sales contract. Also, includes net deferred premiums payable of $5.6 million and $6.2 million related to commodity derivative contracts as of December 31, 2017 and 2016, respectively.

(4) Includes net deferred premiums payable of $4.8 million and $0.6 million related to commodity derivative contracts as of December 31, 2017 and 2016, respectively.

Table of Contents

Type of Contract	Location of Gain/(Loss)	Amount of Gain/(Loss) Years Ended December 31,		
		2017	2016	2015
		(In thousands)		
Derivatives in cash flow hedging relationships:				
Interest rate(1)	Interest expense	$—	$—	$767
Total derivatives in cash flow hedging relationships		$—	$—	$767
Derivatives not designated as hedging instruments:				
Commodity(2)	Oil and gas revenue	$(12,502)	$2,538	$3
Commodity	Derivatives, net	(59,968)	(48,021)	210,649
Interest rate	Interest expense	648	(1,076)	(462)
Total derivatives not designated as hedging instruments		$(71,822)	$(46,559)	$210,190

---

(1) Amounts were reclassified from AOCI into earnings upon settlement.

(2) Amounts represent the change in fair value of our provisional oil sales contracts.

Offsetting of Derivative Assets and Derivative Liabilities

Our derivative instruments which are subject to master netting arrangements with our counterparties only have the right of offset when there is an event of default. As of December 31, 2017 and 2016, there was not an event of default and, therefore, the associated gross asset or gross liability amounts related to these arrangements are presented on the consolidated balance sheets.

10. Fair Value Measurements

In accordance with ASC 820—Fair Value Measurements and Disclosures, fair value measurements are based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. We prioritize the inputs used in measuring fair value into the following fair value hierarchy:

- Level 1—quoted prices for identical assets or liabilities in active markets.
- Level 2—quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs derived principally from or corroborated by observable market data by correlation or other means.
- Level 3—unobservable inputs for the asset or liability. The fair value input hierarchy level to which an asset or liability measurement in its entirety falls is determined based on the lowest level input that is significant to the measurement in its entirety.

The following tables present the Company's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2017 and 2016, for each fair value hierarchy level:

Table of Contents

	Fair Value Measurements Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(In thousands)			
December 31, 2017				
Assets:				
Commodity derivatives	$ —	$ 704	$ —	$ 704
Interest rate derivatives	—	1,017	—	1,017
Liabilities:				
Commodity derivatives	—	(97,740)	—	(97,740)
Interest rate derivatives	—	—	—	—
Total	$ —	$ (96,019)	$ —	$ (96,019)
December 31, 2016				
Assets:				
Commodity derivatives	$ —	$ 34,924	$ —	$ 34,924
Interest rate derivatives	—	582	—	582
Liabilities:				
Commodity derivatives	—	(33,286)	—	(33,286)
Interest rate derivatives	—	(529)	—	(529)
Total	$ —	$ 1,691	$ —	$ 1,691

The book values of cash and cash equivalents and restricted cash approximate fair value based on Level 1 inputs. Joint interest billings, oil sales and other receivables, and accounts payable and accrued liabilities approximate fair value due to the short term nature of these instruments. Our long term receivables, after any allowances for doubtful accounts, and other long-term assets approximate fair value. The estimates of fair value of these items are based on Level 2 inputs.

Commodity Derivatives

Our commodity derivatives represent crude oil collars, put options, call options and swaps for notional barrels of oil at fixed Dated Brent oil prices. The values attributable to our oil derivatives are based on (i) the contracted notional volumes, (ii) independent active futures price quotes for Dated Brent, (iii) a credit adjusted yield curve applicable to each counterparty by reference to the credit default swap ("CDS") market and (iv) an independently sourced estimate of volatility for Dated Brent. The volatility estimate was provided by certain independent brokers who are active in buying and selling oil options and was corroborated by market quoted volatility factors. The deferred premium is included in the fair market value of the commodity derivatives. See Note 9—Derivative Financial Instruments for additional information regarding the Company's derivative instruments.

Provisional Oil Sales

The value attributable to the provisional oil sales derivative is based on (i) the sales volumes and (ii) the difference in the independent active futures price quotes for Dated Brent over the term of the pricing period designated in the sales contract and the spot price on the lifting date.

Interest Rate Derivatives

We enter into interest rate swaps, whereby the Company pays a fixed rate of interest and the counterparty pays a variable LIBOR based rate. We also enter into capped interest rate swaps, whereby the Company pays a fixed rate of interest if LIBOR is below the cap, and pays the market rate less the spread between the cap and the fixed rate of interest if LIBOR is above the cap. The values attributable to the Company's interest rate derivative contracts are based on (i) the contracted notional amounts, (ii) LIBOR yield curves provided by independent third parties and corroborated with forward active market quoted LIBOR yield curves and (iii) a credit adjusted yield curve as applicable to each counterparty by reference to the CDS market.

Table of Contents

Debt

The following table presents the carrying values and fair values at December 31, 2017 and 2016:

	December 31, 2017		December 31, 2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Senior Notes	$507,600	$542,472	$503,716	$528,938
Facility	800,000	800,000	850,000	850,000
Total	$1,307,600	$1,342,472	$1,353,716	$1,378,938

The carrying value of our Senior Notes represents the principal amounts outstanding less unamortized discounts. The fair value of our Senior Notes is based on quoted market prices, which results in a Level 1 fair value measurement. The carrying value of the Facility approximates fair value since it is subject to short-term floating interest rates that approximate the rates available to us for those periods.

11. Asset Retirement Obligations

The following table summarizes the changes in the Company’s asset retirement obligations:

	December 31,	
	2017	2016
	(In thousands)	
Asset retirement obligations:		
Beginning asset retirement obligations	$63,574	$43,938
Liabilities incurred during period	—	14,235
Revisions in estimated retirement obligations	(3,945)	—
Accretion expense	6,966	5,401
Ending asset retirement obligations	$66,595	$63,574

The Ghanaian legal and regulatory regime regarding oil field abandonment and other environmental matters is evolving. Currently, no Ghanaian environmental regulations expressly require that companies abandon or remove offshore assets. Under the Environmental Permit for the Jubilee Field, a decommissioning plan will be prepared and submitted to the Ghana Environmental Protection Agency. ASC 410—Asset Retirement and Environmental Obligations requires the Company to recognize this liability in the period in which the liability was incurred. The TEN fields commenced production during the third quarter of 2016 and an asset retirement obligation was recorded for the facilities and wells that came online during 2016. Additional asset retirement obligations will be recorded in the period in which additional wells within our producing fields are commissioned.

12. Equity based Compensation

Restricted Stock Awards and Restricted Stock Units

Prior to our corporate reorganization in May 2011, Kosmos Energy Holdings issued common units designated as profit units with a threshold value ranging from $0.85 to $90 to employees, management and directors. Profit units were equity awards that were measured on the grant date and expensed over a vesting period of four years. Founding management and directors vested 20% as of the date of issuance and an additional 20% on the anniversary date for each of the next four years. Profit units issued to employees vested 50% on the second and fourth anniversaries of the issuance date.

As part of the corporate reorganization in May 2011, vested profit units were exchanged for 31.7 million common shares of Kosmos Energy Ltd., unvested profit units were exchanged for 10.0 million restricted stock awards and the $90 profit units were cancelled. These restricted stock awards ultimately vested during 2015. Based on the terms and conditions of the corporate reorganization, the exchange of profit units for common shares of Kosmos Energy Ltd. resulted in no incremental compensation costs.

In April 2011, the Board of Directors approved the LTIP, which provides for the granting of incentive awards in the form of stock options, stock appreciation rights, restricted stock awards, restricted stock units, among other award types. In January

Table of Contents

2015, the board of directors approved an amendment to the plan to add 15.0 million shares to the plan which was approved at the Annual General Meeting in June 2015. The LTIP provides for the issuance of 39.5 million shares pursuant to awards under the plan, in addition to the 10.0 million restricted stock awards exchanged for unvested profit units. As of December 31, 2017, the Company had approximately 3.4 million shares that remain available for issuance under the LTIP.

The Company adopted ASU 2016-9, "Improvements to Employee Share-based Payment Accounting" during the second quarter of 2016 using an effective date of January 1, 2016. Prior period compensation expense disclosed below includes estimated forfeitures and has not been adjusted.

We record equity-based compensation expense equal to the fair value of share based payments over the vesting periods of the LTIP awards. We recorded compensation expense from awards granted under our LTIP of $40.0 million, $40.1 million and $75.1 million during the years ended December 31, 2017, 2016 and 2015, respectively. The total tax benefit for the years ended December 31, 2017, 2016 and 2015 was $13.2 million, $13.0 million and $25.7 million, respectively. Additionally, we expensed a tax shortfall related to equity based compensation of $3.1 million, $5.5 million and $18.6 million for the years ended December 31, 2017, 2016 and 2015, respectively. The fair value of awards vested during 2017, 2016 and 2015 was approximately $21.2 million, $14.4 million, and $52.2 million, respectively. The Company granted both restricted stock awards and restricted stock units with service vesting criteria and granted both restricted stock awards and restricted stock units with a combination of market and service vesting criteria under the LTIP. Substantially, all of these awards vest over three or four year periods. Restricted stock awards are issued and included in the number of outstanding shares upon the date of grant and, if such awards are forfeited, they become treasury stock. Upon vesting, restricted stock units become issued and outstanding stock.

The following table reflects the outstanding restricted stock awards as of December 31, 2017:

	Service Vesting Restricted Stock Awards (In thousands)	Weighted-Average Grant-Date Fair Value	Market / Service Vesting Restricted Stock Awards (In thousands)	Weighted-Average Grant-Date Fair Value
Outstanding at December 31, 2014:	3,240	$ 16.95	3,361	$ 13.00
Granted	660	8.64	—	—
Forfeited	(2)	12.84	(1,554)	13.29
Vested	(3,088)	17.21	(1,546)	13.30
Outstanding at December 31, 2015:	810	9.20	261	9.44
Granted	—	—	—	—
Forfeited	—	—	(162)	9.44
Vested	(322)	9.77	(99)	9.44
Outstanding at December 31, 2016:	488	8.83	—	—
Granted	—	—	—	—
Forfeited	—	—	—	—
Vested	(268)	8.97	—	—
Outstanding at December 31, 2017:	220	8.64	—	—

Table of Contents

The following table reflects the outstanding restricted stock units as of December 31, 2017:

	Service Vesting Restricted Stock Units (In thousands)	Weighted-Average Grant-Date Fair Value	Market / Service Vesting Restricted Stock Units (In thousands)	Weighted-Average Grant-Date Fair Value
Outstanding at December 31, 2014:	3,367	$ 10.76	3,246	$ 15.66
Granted	1,539	8.37	3,544	12.96
Forfeited	(254)	10.14	(212)	14.48
Vested	(1,060)	10.71	—	—
Outstanding at December 31, 2015:	3,592	9.79	6,578	14.24
Granted	2,158	4.05	1,379	4.88
Forfeited	(134)	8.87	(70)	14.49
Vested	(1,456)	9.61	(693)	15.81
Outstanding at December 31, 2016:	4,160	6.91	7,194	12.29
Granted	2,085	6.43	2,175	9.50
Forfeited	(137)	6.91	(21)	6.21
Vested	(1,925)	7.51	(896)	15.43
Outstanding at December 31, 2017:	4,183	6.39	8,452	11.26

As of December 31, 2017, total equity based compensation to be recognized on unvested restricted stock awards and restricted stock units is $23.6 million over a weighted average period of 1.5 years.

For restricted stock awards and restricted stock units with a combination of market and service vesting criteria, the number of common shares to be issued is determined by comparing the Company's total shareholder return with the total shareholder return of a predetermined group of peer companies over the performance period and can vest up to 100% of the awards granted for restricted stock awards and up to 200% of the awards granted for restricted stock units. The grant date fair value of these awards ranged from $6.70 to $13.57 per award for restricted stock awards and $4.83 to $15.81 per award for restricted stock units. The Monte Carlo simulation model utilizes multiple input variables that determine the probability of satisfying the market condition stipulated in the award grant and calculates the fair value of the award. The expected volatility utilized in the model was estimated using our historical volatility and the historical volatilities of our peer companies and ranged from 41.3% to 56.7% for restricted stock awards and 44.0% to 54.0% for restricted stock units. The risk free interest rate was based on the U.S. treasury rate for a term commensurate with the expected life of the grant was 0.5% for restricted stock awards and and ranged from 0.5% to 1.4% for restricted stock units.

For profit units that were exchanged for restricted stock awards, the significant assumptions used to calculate the fair values of the profit units granted as calculated using a binomial tree, were as follows: no dividend yield, expected volatility ranging from approximately 25% to 66%; risk free interest rate ranging from 1.3% to 5.1%; expected life ranging from 1.2 to 8.1 years; and projected turnover rates ranging from 7.0% to 27.0% for employees and none for management. For profit units granted immediately prior to our initial public offering, we utilized the midpoint of the range of the estimated offering price, or $17.00 per share.

In January 2018, we granted 1.8 million service vesting restricted stock units and 2.3 million market and service vesting restricted stock units to our employees under our long-term incentive plan. We expect to recognize approximately $34.3 million of non-cash compensation expense related to these grants over the next three years.

13. Income Taxes

Kosmos Energy Ltd. is a Bermuda company that is not subject to taxation at the corporate level. We provide for income taxes based on the laws and rates in effect in the countries in which our operations are conducted. The relationship between our pre tax income or loss from continuing operations and our income tax expense or benefit varies from period to period as a result of various factors which include changes in total pre tax income or loss, the jurisdictions in which our income (loss) is earned and the tax laws in those jurisdictions.

Table of Contents

On December 22, 2017, the President of the United States signed P.L. 115-97, the Tax Cut and Jobs Act (the Tax Reform Act), into law. Many of the provisions of the Tax Reform Act are effective beginning January 1, 2018, most notable of which is the reduction in the U.S. corporate income tax rate from 35% to 21%. Accounting Standards Codification Topic 740 requires deferred tax assets and liabilities be adjusted for the effect of changes in tax laws or tax rates during the period that includes the date of enactment. Accordingly, we have recorded a $16.7 million charge to deferred tax expense in December 2017 as a result of reducing our net deferred tax assets.

The components of income (loss) before income taxes were as follows:

	Years Ended December 31,		
	2017	2016	2015
	(In thousands)		
Bermuda	$(66,914)	$(63,749)	$(62,372)
United States	6,068	5,083	10,652
Foreign—other	(117,009)	(235,898)	137,156
Income (loss) before income taxes	$(177,855)	$(294,564)	$85,436

The components of the provision for income taxes attributable to our income (loss) before income taxes consist of the following:

	Years Ended December 31,		
	2017	2016	2015
	(In thousands)		
Current:			
Bermuda	$—	$—	$—
United States	10,976	12,675	15,199
Foreign—other	24,456	102	29,287
Total current	35,432	12,777	44,486
Deferred:			
Bermuda	—	—	—
United States	15,310	(3,594)	8,241
Foreign—other	(5,805)	(19,967)	102,545
Total deferred	9,505	(23,561)	110,786
Income tax expense (benefit)	$44,937	$(10,784)	$155,272

Our reconciliation of income tax expense (benefit) computed by applying our Bermuda statutory rate and the reported effective tax rate on income (loss) from continuing operations is as follows:

	Years Ended December 31,		
	2017	2016	2015
	(In thousands)		
Tax at Bermuda statutory rate	$—	$—	$—
Foreign income (loss) taxed at different rates	(1,978)	(57,898)	94,184
Change in valuation allowance and the expiration of fully valued deferred tax assets	6,008	29,263	40,600
Non-deductible and other items(1)	21,100	12,347	1,885
Tax shortfall on equity-based compensation	3,086	5,504	18,603
Change in U.S. tax rate	16,721	—	—
Total tax expense (benefit)	$44,937	$(10,784)	$155,272
Effective tax rate(2)	25%	4%	182%

(1) Includes $5.0 million of tax expense related to the expiration of a Moroccan tax loss carryforward; $4.7 million of tax related interest expense incurred in 2017; and other various items.

Table of Contents

(2) The effective tax rate during the years ended December 31, 2017, 2016 and 2015 were impacted by losses of $164.4 million, $121.4 million and $153.5 million, respectively, incurred in jurisdictions in which we are not subject to taxes and therefore do not generate any income tax benefits.

The effective tax rate for the United States is approximately 433%, 179% and 220% for the years ended December 31, 2017, 2016 and 2015, respectively. The effective tax rate in the United States is impacted by the effect of writing-down our deferred tax assets as a result of the change in tax rate under the Act and the sum of equity-based compensation tax shortfalls and tax windfalls equal to the difference between the income tax benefit recognized for financial statement reporting purposes compared to the income tax benefit realized for tax return purposes.

The effective tax rate for Ghana is approximately 49%, 23% and 35% for the years ended December 31, 2017, 2016 and 2015, respectively. The effective tax rate in Ghana is impacted by non-deductible expenditures, including amounts associated with the damage to the turret bearing, which we expect to recover from insurance proceeds. Any such insurance recoveries would not be subject to income tax.

Our operations in other foreign jurisdictions have a 0% effective tax rate because they reside in countries with a 0% statutory rate or we have incurred losses in those countries and have full valuation allowances against the corresponding net deferred tax assets.

Deferred tax assets and liabilities, which are computed on the estimated income tax effect of temporary differences between financial and tax bases in assets and liabilities, are determined using the tax rates expected to be in effect when taxes are actually paid or recovered. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. The tax effects of significant temporary differences giving rise to deferred tax assets and liabilities are as follows:

	December 31,	
	2017	2016
	(In thousands)	
Deferred tax assets:		
Foreign capitalized operating expenses	$68,218	$69,804
Foreign net operating losses	25,307	36,352
Equity compensation	20,783	30,752
Unrealized derivative losses	33,963	—
Asset retirement obligation and other	24,784	33,744
Total deferred tax assets	173,055	170,652
Valuation allowance	(93,525)	(87,517)
Total deferred tax assets, net	79,530	83,135
Deferred tax liabilities:		
Depletion, depreciation and amortization related to property and equipment	(533,561)	(526,945)
Unrealized derivative gains	—	(584)
Total deferred tax liabilities	(533,561)	(527,529)
Net deferred tax liability	$(454,031)	$(444,394)

The Company has recorded a full valuation allowance against the net deferred tax assets in countries where we only have exploration operations.

The Company has foreign net operating loss carryforwards of $94.1 million. Of these losses, we expect $0.9 million, $0.5 million, $0.5 million, $0.6 million, $0.7 million and $15.0 million to expire in 2019, 2020, 2021, 2022, 2023 and 2029, respectively, and $75.9 million do not expire. All of these losses currently have offsetting valuation allowances.

A subsidiary of the Company files a U.S. federal income tax return and a Texas margin tax return. The Company is open to U.S. federal income tax examinations for tax years 2014 through 2017 and to Texas margin tax examinations for the tax years 2011 through 2017. In addition to the United States, the Company files income tax returns in the countries in which we operate.

118

Table of Contents

The Company is open to income tax examinations for years 2014 through 2017 in its significant other foreign jurisdictions, primarily Ghana.
As of December 31, 2017, the Company had no material uncertain tax positions. The Company's policy is to recognize potential interest and penalties related to income tax matters in income tax expense.

14. Net Income (Loss) Per Share
In the calculation of basic net income per share, participating securities are allocated earnings based on actual dividend distributions received plus a proportionate share of undistributed net income, if any. We calculate basic net income per share under the two class method. Diluted net income (loss) per share is calculated under both the two-class method and the treasury stock method and the more dilutive of the two calculations is presented. The computation of diluted net income (loss) per share reflects the potential dilution that could occur if all outstanding awards under our LTIP were converted into common shares or resulted in the issuance of common shares that would then share in the earnings of the Company. During periods in which the Company realizes a loss from continuing operations securities would not be dilutive to net loss per share and conversion into common shares is assumed not to occur.
Basic net income (loss) per share is computed as (i) net income (loss), (ii) less income allocable to participating securities (iii) divided by weighted average basic shares outstanding. The Company's diluted net income (loss) per share is computed as (i) basic net income (loss), (ii) plus diluted adjustments to income allocable to participating securities (iii) divided by weighted average diluted shares outstanding.

	Years Ended December 31,		
	2017	2016	2015
	(In thousands, except per share data)		
Numerator:			
Net loss	(222,792)	(283,780)	$(69,836)
Basic income allocable to participating securities(1)	—	—	—
Basic net loss allocable to common shareholders	(222,792)	(283,780)	(69,836)
Diluted adjustments to income allocable to participating securities(1)	—	—	—
Diluted net loss allocable to common shareholders	(222,792)	(283,780)	$(69,836)
Denominator:			
Weighted average number of shares outstanding:			
Basic	388,375	385,402	382,610
Restricted stock awards and units(1)(2)	—	—	—
Diluted	388,375	385,402	382,610
Net loss per share:			
Basic	$(0.57)	$(0.74)	$(0.18)
Diluted	$(0.57)	$(0.74)	$(0.18)

(1) Our service vesting restricted stock awards represent participating securities because they participate in non-forfeitable dividends with common equity owners. Income allocable to participating securities represents the distributed and undistributed earnings attributable to the participating securities. Our restricted stock awards with market and service vesting criteria and all restricted stock units are not considered to be participating securities and, therefore, are excluded from the basic net income (loss) per common share calculation. Our service vesting restricted stock awards do not participate in undistributed net losses because they are not contractually obligated to do so and, therefore, are excluded from the basic net income (loss) per common share calculation in periods we are in a net loss position.

(2)

For the years ended December 31, 2017, 2016 and 2015, we excluded 12.9 million, 11.8 million and 11.2 million outstanding restricted stock awards and restricted stock units, respectively, from the computations of diluted net income per share because the effect would have been anti dilutive.

15. Commitments and Contingencies

From time to time, we are involved in litigation, regulatory examinations and administrative proceedings primarily arising in the ordinary course of our business in jurisdictions in which we do business. Although the outcome of these matters cannot be predicted with certainty, management believes none of these matters, either individually or in the aggregate, would have a material effect upon the Company's financial position; however, an unfavorable outcome could have a material adverse effect on our results from operations for a specific interim period or year.

The Jubilee Field in Ghana covers an area within both the WCTP and DT petroleum contract areas. It was agreed the Jubilee Field would be unitized for optimal resource recovery. Kosmos and its partners executed a comprehensive unitization and unit operating agreement, the Jubilee UUOA, to unitize the Jubilee Field and govern each party's respective rights and duties in the Jubilee Unit, which was effective July 16, 2009. Pursuant to the terms of the Jubilee UUOA, the tract participations are subject to a process of redetermination. The initial redetermination process was completed on October 14, 2011. As a result of the initial redetermination process, our Unit Interest is 24.1%. These consolidated financial statements are based on these re determined tract participations. Our unit interest may change in the future should another redetermination occur.

The Company leases facilities under various operating leases that expire through 2027, including our office space. Rent expense under these agreements, was $3.3 million, $3.3 million and $4.7 million for the years ended December 31, 2017, 2016 and 2015, respectively.

We currently have a commitment to drill one exploration well in Mauritania. In Mauritania, our partner is obligated to fund our share of the cost of the exploration well, subject to their maximum $228 million cumulative exploration and appraisal carry covering both our Mauritania and Senegal blocks. In Equatorial Guinea, Mauritania and Cote d'Ivoire, we have 3D seismic requirements of approximately 6,000 square kilometers, 7,600 square kilometers and 12,000 square kilometers, respectively. The Equatorial Guinea exploration block commitments are subject to ratification by the President of Equatorial Guinea.

In November 2017, we entered into a one well drilling rig contract for the ENSCO DS-12 plus six well options. We have completed the initial well and have exercised one of the six option wells to be drilled in 2018.

Future minimum rental commitments under our leases at December 31, 2017, are as follows:

	Payments Due By Year(1)						
	Total	2018	2019	2020	2021	2022	Thereafter
	(In thousands)						
Operating leases(2)	$12,626	$4,981	$4,370	$484	$419	$418	$ 1,954

(1) Does not include purchase commitments for jointly owned fields and facilities where we are not the operator and excludes commitments for exploration activities, including well commitments, in our petroleum contracts.

(2) Primarily relates to corporate office and foreign office leases.

Table of Contents

16. Additional Financial Information
Accrued Liabilities
Accrued liabilities consisted of the following:

	December 31,	
	2017	2016
	(In thousands)	
Accrued liabilities:		
Exploration, development and production	$144,717	$76,194
General and administrative expenses	31,124	31,243
Interest	20,457	17,247
Income taxes	17,423	2,579
Taxes other than income	3,270	1,914
Other	2,421	529
	$219,412	$129,706

Other Income, net
Other income, net consisted of $58.7 million, $74.8 million and zero of Loss of Production Income ("LOPI") proceeds related to the turret bearing issue on the Jubilee FPSO for the years ended December 31, 2017, 2016 and 2015.
Oil and Gas Production
Oil and gas production expense included insurance recoveries related to our increased cost of working covered by our LOPI policy of $17.1 million, $7.5 million, and zero for the years ended December 31, 2017, 2016 and 2015, respectively.
Facilities Insurance Modifications, net
Facilities insurance modifications consist of costs associated with the long-term solution to convert the FPSO to a permanently spread moored facility which we expect to recover from our insurance policy. Any insurance reimbursement of these costs is also be recorded to this line.
Other Expenses, net
Other expenses, net incurred during the period is comprised of the following:

	Years Ended December 31,		
	2017	2016	2015
	(In thousands)		
Inventory write-off	$866	$14,900	$36
(Gain) loss on insurance settlements	(461)	(4,003)	4,151
Disputed charges and related costs	4,962	11,299	—
Other, net	(76)	920	1,059
Other expenses, net	$5,291	$23,116	$5,246

The disputed charges and related costs are expenditures arising from Tullow Ghana Limited's contract with Seadrill for use of the West Leo drilling rig once partner-approved 2016 work program objectives were concluded. Tullow has charged such expenditures to the Deepwater Tano ("DT") joint account. Kosmos disputes that these expenditures are chargeable to the DT joint account on the basis that the Seadrill West Leo drilling rig contract was not approved by the DT operating committee pursuant to the DT Joint Operating Agreement.

Table of Contents

KOSMOS ENERGY LTD.

Supplemental Oil and Gas Data (Unaudited)

Net proved oil and gas reserve estimates presented were prepared by Ryder Scott Company, L.P. ("RSC") for the years ended December 31, 2017, 2016 and 2015. RSC are independent petroleum engineers located in Houston, Texas. RSC has prepared the reserve estimates presented herein and meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to independent reserve engineers for their reserves estimation process.

Net Proved Developed and Undeveloped Reserves

The following table is a summary of net proved developed and undeveloped oil and gas reserves to Kosmos' interest in the Jubilee and TEN fields in Ghana and our equity method investment.

	Kosmos Entities			Equity Method Investment - Equatorial Guinea			
	Oil (MMBbl)	Gas (Bcf)	Total (MMBoe)	Oil (MMBbl)	Gas (Bcf)	Total (MMBoe)	Total (MMBoe)
Net proved developed and undeveloped reserves at December 31, 2014(1)	73	14	75	—	—	—	75
Production	(9)	(1)	(9)	—	—	—	(9)
Revision in estimate(3)	10	1	10	—	—	—	10
Net proved developed and undeveloped reserves at December 31, 2015(1)	74	14	76	—	—	—	76
Production	(7)	(1)	(7)	—	—	—	(7)
Revision in estimate(4)	7	2	8	—	—	—	8
Net proved developed and undeveloped reserves at December 31, 2016(1)	74	15	77	—	—	—	77
Extensions and discoveries	1	—	1	—	—	—	1
Production	(11)	(1)	(11)	(1)	—	(1)	(12)
Revision in estimate(5)	18	35	24	—	—	—	24
Purchases of minerals-in-place(6)	—	—	—	20	13	21	21
Net proved developed and undeveloped reserves at December 31, 2017(1)	82	49	89	19	13	21	110
Proved developed reserves(1)							
December 31, 2015	50	10	52	—	—	—	52
December 31, 2016	64	13	66	—	—	—	66
December 31, 2017	59	38	65	18	13	20	85
Proved undeveloped reserves(1)							
December 31, 2015	24	4	25	—	—	—	25
December 31, 2016	10	2	11	—	—	—	11
December 31, 2017	23	11	24	1	—	1	25

(1) The sum of proved developed reserves and proved undeveloped reserves may not add to net proved developed and undeveloped reserves as a result of rounding.

(2) Discoveries are related to the TEN fields being moved from unproved to proved during 2014.

(3) The increase in proved reserves is a result of a 2 MMBbl increase associated with in-fill drilling results and a 10 MMBbl increase associated with field performance for Jubilee partially offset by 2 MMBbl of negative revisions to

the TEN fields due to decreased pricing.

Table of Contents

(4) The increase in proved reserves is a result of an 8 MMBbl increase associated with positive revisions to the TEN fields as a result of the completion of seven wells along with the initiation of TEN production partially offset by 1 MMBbl of negative revisions to the Jubilee Field due to decreased pricing.

(5) The increase in proved reserves is a result of a 16 MMBbl increase associated in Jubilee related to the approval of the Greater Jubilee Full Field Development Plan (GJFFDP) and an 8 MMBoe increase associated with positive revisions to the TEN fields.

(6) The increase in purchase of minerals in place is related to Equatorial Guinea, representing the reserves associated with our equity method investment.

Net proved reserves were calculated utilizing the twelve month unweighted arithmetic average of the first day of the month oil price for each month for Brent crude in the period January through December 2017. The average 2017 Brent crude price of $54.42 per barrel is adjusted for crude handling, transportation fees, quality, and a regional price differential. Based on the crude quality, these adjustments are estimated to be $0.10 premium, $0.02 premium and $0.53 discount per barrel for Jubilee, TEN and our equity method investment, respectively; therefore, the adjusted oil price is $54.52, $54.44 and $53.89 per barrel for Jubilee, TEN and our equity method investment, respectively.

Proved oil and gas reserves are defined by the SEC Rule 4.10(a) of Regulation S X as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recovered under current economic conditions, operating methods, and government regulations. Inherent uncertainties exist in estimating proved reserve quantities, projecting future production rates and timing of development expenditures.

Capitalized Costs Related to Oil and Gas Activities

The following table presents aggregate capitalized costs related to oil and gas activities:

	Ghana	Other(1)	Kosmos Total	Equity Method Investment-Equatorial Guinea(2)	Total
	(In thousands)				
As of December 31, 2017					
Unproved properties	$55,179	$409,930	$465,109	$ —	$465,109
Proved properties	3,080,670	—	3,080,670	2,850,521	5,931,191
	3,135,849	409,930	3,545,779	2,850,521	6,396,300
Accumulated depletion	(1,234,806)	—	(1,234,806)	(2,678,897)	(3,913,703)
Net capitalized costs	$1,901,043	$409,930	$2,310,973	$ 171,624	$2,482,597
As of December 31, 2016					
Unproved properties	$347,950	$571,106	$919,056		
Proved properties	2,771,779	—	2,771,779		
	3,119,729	571,106	3,690,835		
Accumulated depletion	(989,946)	—	(989,946)		
Net capitalized costs	$2,129,783	$571,106	$2,700,889		

(1) Includes Africa, excluding Ghana, Europe and South America.

(2) Represents 50% interest in KTIPI's capitalized costs related to oil and gas activities.

Table of Contents

Costs Incurred in Oil and Gas Activities

The following tables reflects total costs incurred, both capitalized and expensed, for oil and gas property acquisition, exploration, and development activities for the year.

	Ghana	Other(1)	Kosmos Total	Equity Method Investment-Equatorial Guinea(2)	Total
	(In thousands)				
Year ended December 31, 2017					
Property acquisition:					
Unproved	$—	$9,865	$9,865	$ —	$9,865
Proved(3)	—	231,280	231,280	—	231,280
Exploration	15,150	55,632	70,782	—	70,782
Development	1,364	—	1,364	—	1,364
Total costs incurred	$16,514	$296,777	$313,291	$ —	$313,291
Year ended December 31, 2016					
Property acquisition:					
Unproved	$—	$17,322	$17,322		
Proved	—	—	—		
Exploration	11,871	425,229	437,100		
Development	265,451	—	265,451		
Total costs incurred	$277,322	$442,551	$719,873		
Year ended December 31, 2015					
Property acquisition:					
Unproved	$—	$6,250	$6,250		
Proved	—	—	—		
Exploration(4)	12,441	367,196	379,637		
Development	462,066	—	462,066		
Total costs incurred	$474,507	$373,446	$847,953		

(1) Includes Africa, excluding Ghana, Europe and South America.

(2) Represents 50% interest in KTIPI costs incurred from the date of acquisition through December 31, 2017.

(3) Represents cash paid to acquire 50% interest in KTIPI.

(4) Does not include reimbursement of costs associated with exploration expenses incurred in prior years which resulted in a $24.7 million gain on sale in 2015.

Standardized Measure for Discounted Future Net Cash Flows

The following table provides projected future net cash flows based on the twelve month unweighted arithmetic average of the first day of the month oil price for Brent crude in the period January through December 2017. The average 2017 Brent crude price of $54.42 per barrel is adjusted for crude handling, transportation fees, quality, and a regional price differential. Based on the crude quality, these adjustments are estimated to be $0.10 premium, a $0.02 premium and a $0.53 discount relative to Dated Brent for the Jubilee Field, TEN fields and our equity method investment, respectively. The adjusted price utilized to derive the Jubilee Field PV 10, TEN PV-10 and equity method investment PV-10 is $54.52, $54.44 and $53.89, respectively.

Because prices used in the calculation are average prices for that year, the standardized measure could vary significantly from year to year based on market conditions that occur.

The projection should not be interpreted as representing the current value to Kosmos. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary. Kosmos' investment and operating

Table of Contents

decisions are not based on the information presented, but on a wide range of reserve estimates that include probable as well as proved reserves and on a wide range of different price and cost assumptions.

The standardized measure is intended to provide a better means to compare the value of Kosmos' proved reserves at a given time with those of other oil producing companies than is provided by comparing raw proved reserve quantities.

	Ghana	Equity Method Investment-Equatorial Guinea	Total
	(In millions)		
At December 31, 2017			
Future cash inflows	$ 4,473	$ 1,003	$5,476
Future production costs	(1,925)	(473)	(2,398)
Future development costs	(1,059)	(296)	(1,355)
Future Ghanaian tax expenses(1)	(203)	(225)	(428)
Future net cash flows	1,286	9	1,295
10% annual discount for estimated timing of cash flows	(315)	121	(194)
Standardized measure of discounted future net cash flows	$ 971	$ 130	$1,101
At December 31, 2016			
Future cash inflows	$ 3,204		
Future production costs	(1,437)		
Future development costs	(428)		
Future Ghanaian tax expenses(1)	(228)		
Future net cash flows	1,111		
10% annual discount for estimated timing of cash flows	(265)		
Standardized measure of discounted future net cash flows	$ 846		
At December 31, 2015			
Future cash inflows	$ 3,998		
Future production costs	(1,362)		
Future development costs	(679)		
Future Ghanaian tax expenses(1)	(411)		
Future net cash flows	1,546		
10% annual discount for estimated timing of cash flows	(377)		
Standardized measure of discounted future net cash flows	$ 1,169		

(1) The Company is a tax exempt company incorporated pursuant to the laws of Bermuda. The Company has not been and does not expect to be subject to future income tax expense related to its proved oil and gas reserves levied at a corporate parent level. Accordingly, the Company's Standardized Measure for the years ended December 31, 2017, 2016 and 2015, respectively, only reflect the effects of future tax expense levied at an asset level (in the Company's case, future Ghanaian tax expense).

Table of Contents

Changes in the Standardized Measure for Discounted Cash Flows

	Ghana	Equity Method Investment-Equatorial Guinea	Total
	(In millions)		
Balance at December 31, 2014	$ 2,383	$ —	$2,383
Sales and transfers 2015	(341)	—	(341)
Net changes in prices and costs	(2,842)	—	(2,842)
Previously estimated development costs incurred during the period	417	—	417
Net changes in development costs	6	—	6
Revisions of previous quantity estimates	375	—	375
Net changes in Ghanaian tax expenses(1)	802	—	802
Accretion of discount	341	—	341
Changes in timing and other	28	—	28
Balance at December 31, 2015	$ 1,169	$ —	$1,169
Sales and transfers 2016	(191)	—	(191)
Net changes in prices and costs	(653)	—	(653)
Previously estimated development costs incurred during the period	225	—	225
Net changes in development costs	4	—	4
Revisions of previous quantity estimates	65	—	65
Net changes in Ghanaian tax expenses(1)	143	—	143
Accretion of discount	145	—	145
Changes in timing and other	(61)	—	(61)
Balance at December 31, 2016	$ 846	$ —	$846
Purchase of minerals in place	—	146	146
Sales and transfers 2017	(451)	(16)	(467)
Extensions and discoveries	21	—	21
Net changes in prices and costs	485	—	485
Previously estimated development costs incurred during the period	6	—	6
Net changes in development costs	(388)	—	(388)
Revisions of previous quantity estimates	415	—	415
Net changes in tax expenses(1)	(8)	—	(8)
Accretion of discount	98	—	98
Changes in timing and other	(53)	—	(53)
Balance at December 31, 2017	$ 971	$ 130	$1,101

(1) The Company is a tax exempt company incorporated pursuant to the laws of Bermuda. The Company has not been and does not expect to be subject to future income tax expense related to its proved oil and gas reserves levied at a corporate parent level. Accordingly, the Company's Standardized Measure for the years ended December 31, 2017, 2016 and 2015, respectively, only reflect the effects of future tax expense levied at an asset level (in the Company's case, future Ghanaian tax expense).

Table of Contents

KOSMOS ENERGY LTD.
Supplemental Quarterly Financial Information (Unaudited)

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
	(In thousands, except per share data)			
2017				
Revenues and other income	$151,966	$146,524	$ 151,242	$ 187,104
Costs and expenses	158,630	131,252	216,162	308,647
Net loss	(28,841)	(8,467)	(63,405)	(122,079)
Net loss per share:				
Basic(1)	(0.07)	(0.02)	(0.16)	(0.31)
Diluted(1)	(0.07)	(0.02)	(0.16)	(0.31)
2016				
Revenues and other income	$62,133	$45,676	$ 66,629	$ 210,917
Costs and expenses	123,148	169,544	118,890	268,337
Net loss	(58,993)	(108,324)	(59,763)	(56,700)
Net loss per share:				
Basic(1)	(0.15)	(0.28)	(0.15)	(0.15)
Diluted(1)	(0.15)	(0.28)	(0.15)	(0.15)

(1) The sum of the quarterly earnings per share information may not add to the annual earnings per share information as a result of rounding.

Table of Contents

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a 15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was performed under the supervision and with the participation of the Company's management, including our Chief Executive Officer and Chief Financial Officer. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports we file or submit under the Exchange Act is accurate, complete and timely. However, 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. The design of a control system must reflect the fact that there are resource constraints, and the benefit of controls must be considered relative to their costs. Consequently, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Based upon this evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2017, in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, including that such information is accumulated and communicated to the Company's management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosure.

Evaluation of Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during our most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control has been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles. All internal control systems have inherent limitations, including the possibility of human error and the possible circumvention of or overriding of controls. The design of an internal control system is also based in part upon assumptions and judgments made by management. As a result, even an effective system of internal controls can provide no more than reasonable assurance with respect to the fair presentation of financial statements and the processes under which they were prepared. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that internal control may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of the end of the period covered by this report based on the framework in "Internal Control—Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, our Chief Executive Officer and our Chief Financial Officer concluded that our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

Ernst & Young LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this annual report on Form 10 K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2017 which is included in "Item 8. Financial Statements and Supplementary Data."

Item 9B. Other Information

Disclosures Required Pursuant to Section 13(r) of the Securities Exchange Act of 1934

Under the Iran Threat Reduction and Syria Human Rights Act of 2012, which added Section 13(r) of the Exchange Act, we are required to include certain disclosures in our periodic reports if we or any of our “affiliates” (as defined in Rule 12b 2

128

Table of Contents

under the Exchange Act) knowingly engaged in certain specified activities during the period covered by the report. Because the Securities and Exchange Commission (“SEC”) defines the term “affiliate” broadly, it includes any entity controlled by us as well as any person or entity that controls us or is under common control with us (“control” is also construed broadly by the SEC).

We are not presently aware that we and our consolidated subsidiaries have knowingly engaged in any transaction or dealing reportable under Section 13(r) of the Exchange Act during the fiscal quarter ended December 31, 2017. In addition, except as described below, at the time of filing this annual report on Form 10 K, we are not aware of any such reportable transactions or dealings by companies that may be considered our affiliates as to whether they have knowingly engaged in any such reportable transactions or dealings during such period. Upon the filing of periodic reports by such other companies for the fiscal quarter or fiscal year ended December 31, 2017, as the case may be, additional reportable transactions may be disclosed by such companies.

As of December 31, 2017, funds affiliated with Warburg Pincus (“Warburg Pincus”) held approximately 24% of our outstanding common shares. We are also a party to a shareholders agreement with Warburg Pincus pursuant to which, among other things, Warburg Pincus currently has the right to designate two members of our board of directors. Accordingly, Warburg Pincus may be deemed an “affiliate” of us, both currently and during the fiscal quarter ended December 31, 2017.

Disclosure relating to Warburg Pincus and its affiliates

Warburg Pincus informed us of (i) the information reproduced below (the “SAMIH Disclosure”) regarding Santander Asset Management Investment Holdings Limited (“SAMIH. SAMIH is a company that may be considered an affiliate of Warburg Pincus. Because we and SAMIH may be deemed to be controlled by Warburg Pincus, we may be considered an “affiliate” of each of SAMIH for the purposes of Section 13(r) of the Exchange Act.

SAMIH Disclosure:

Quarter ended December 31, 2017

“Santander UK plc (“Santander UK”) holds two savings accounts and one current account for two customers resident in the United Kingdom (“UK”) who are currently designated by the United States (“US”) under the Specially Designated Global Terrorist (“SDGT”) sanctions program. Revenues and profits generated by Santander UK on these accounts in the year ended December 31, 2017 were negligible relative to the overall revenues and profits of Banco Santander SA. Santander UK holds two frozen current accounts for two UK nationals who are designated by the US under the SDGT sanctions program. The accounts held by each customer have been frozen since their designation and have remained frozen through the year ended December 31, 2017. The accounts are in arrears (£1,844.73 in debit combined) and are currently being managed by Santander UK Collections & Recoveries department. No revenues or profits were generated by Santander UK on this account in the year ended December 31, 2017.”

The SAMIH Disclosure relates solely to activities conducted by SAMIH and do not relate to any activities conducted by us. We have no involvement in or control over the activities of SAMIH, any of its predecessor companies or any of its subsidiaries. Other than as described above, we have no knowledge of the activities of SAMIH with respect to transactions with Iran, and we have not participated in the preparation of the SAMIH Disclosure. We have not independently verified the SAMIH Disclosure, are not representing to the accuracy or completeness of the SAMIH Disclosure and undertake no obligation to correct or update the SAMIH Disclosure.

Table of Contents

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the 2017 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2017 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017.

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

The information required by this item is incorporated herein by reference to the 2017 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017.

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

The information required by this item is incorporated herein by reference to the 2017 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2017 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017.

Table of Contents

PART IV
Item 15. Exhibits, Financial Statement Schedules
(a) The following documents are filed as part of this report:
(1) Financial statements
The financial statements filed as part of the Annual Report on Form 10 K are listed in the accompanying index to consolidated financial statements in Item 8, Financial Statements and Supplementary Data.
(2) Financial statement schedules
Schedule I—Condensed Parent Company Financial Statements
Under the terms of agreements governing the indebtedness of subsidiaries of Kosmos Energy Ltd. for 2017, 2016 and 2015 (collectively “KEL,” the “Parent Company”), such subsidiaries are restricted from making dividend payments, loans or advances to KEL. Schedule I of Article 5 04 of Regulation S X requires the condensed financial information of the Parent Company to be filed when the restricted net assets of consolidated subsidiaries exceed 25 percent of consolidated net assets as of the end of the most recently completed fiscal year.
The following condensed parent only financial statements of KEL have been prepared in accordance with Rule 12 04, Schedule I of Regulation S X and included herein. The Parent Company’s 100% investment in its subsidiaries has been recorded using the equity basis of accounting in the accompanying condensed parent only financial statements. The condensed financial statements should be read in conjunction with the consolidated financial statements of Kosmos Energy Ltd. and subsidiaries and notes thereto.
The terms “Kosmos,” the “Company,” and similar terms refer to Kosmos Energy Ltd. and its wholly owned subsidiaries, unless the context indicates otherwise. Certain prior period amounts have been reclassified to conform with the current year presentation. Such reclassifications had no impact on our reported net income, current assets, total assets, current liabilities, total liabilities or shareholders equity.

Table of Contents

KOSMOS ENERGY LTD.
CONDENSED PARENT COMPANY BALANCE SHEETS
(In thousands, except share data)

	December 31, 2017	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	$297	$1,092
Receivables from subsidiaries	—	14,131
Prepaid expenses and other	290	417
Total current assets	587	15,640
Investment in subsidiaries at equity	1,419,890	1,580,459
Deferred financing costs, net of accumulated amortization of $13,951 and $11,213 at December 31, 2017 and December 31, 2016, respectively	2,510	5,248
Total assets	$1,422,987	$1,601,347
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable	$4	$13
Accounts payable to subsidiaries	332	—
Accrued liabilities	19,128	17,939
Total current liabilities	19,464	17,952
Long-term debt	506,411	502,196
Shareholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2017 and December 31, 2016	—	—
Common shares, $0.01 par value; 2,000,000,000 authorized shares; 398,599,457 and 395,859,061 issued at December 31, 2017 and December 31, 2016, respectively	3,986	3,959
Additional paid-in capital	2,014,525	1,975,247
Accumulated deficit	(1,073,202)	(850,410)
Treasury stock, at cost, 9,188,819 and 9,101,395 shares at December 31, 2017 and December 31, 2016, respectively	(48,197)	(47,597)
Total shareholders' equity	897,112	1,081,199
Total liabilities and shareholders' equity	$1,422,987	$1,601,347

Table of Contents

KOSMOS ENERGY LTD.
CONDENSED PARENT COMPANY STATEMENTS OF OPERATIONS
(In thousands)

	Years Ended December 31,		
	2017	2016	2015
Revenues and other income:			
Oil and gas revenue	$—	$—	$—
Total revenues and other income	—	—	—
Costs and expenses:			
General and administrative	51,544	48,542	85,103
General and administrative recoveries—related party	(40,266)	(40,047)	(72,543)
Interest and other financing costs, net	55,596	55,253	49,572
Other expenses, net	40	1	240
Equity in losses of subsidiaries	155,878	220,031	7,464
Total costs and expenses	222,792	283,780	69,836
Loss before income taxes	(222,792)	(283,780)	(69,836)
Income tax expense	—	—	—
Net loss	$(222,792)	$(283,780)	$(69,836)

Table of Contents

KOSMOS ENERGY LTD.
CONDENSED PARENT COMPANY STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31,		
	2017	2016	2015
Operating activities			
Net loss	$(222,792)	$(283,780)	$(69,836)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Equity in losses of subsidiaries	155,878	220,031	7,464
Equity-based compensation	39,913	40,423	75,267
Amortization	3,070	3,070	3,190
Other	3,884	3,530	2,704
Changes in assets and liabilities:			
Decrease in receivables	986	—	—
(Increase) decrease in prepaid expenses and other	127	52	(34)
(Increase) decrease due to/from related party	14,463	(15,201)	1,224
Increase in accounts payable and accrued liabilities	1,179	312	2,721
Net cash provided by (used in) operating activities	(3,292)	(31,563)	22,700
Investing activities			
Investment in subsidiaries	4,691	(40,047)	(293,545)
Net cash provided by (used in) investing activities	4,691	(40,047)	(293,545)
Financing activities			
Net proceeds from issuance of senior secured notes	—	—	206,774
Purchase of treasury stock	(2,194)	(1,981)	(18,110)
Deferred financing costs	—	—	(9,030)
Net cash provided by (used in) financing activities	(2,194)	(1,981)	179,634
Net decrease in cash and cash equivalents	(795)	(73,591)	(91,211)
Cash and cash equivalents at beginning of period	1,092	74,683	165,894
Cash and cash equivalents at end of period	$297	$1,092	$74,683

Table of Contents

Schedule II
Kosmos Energy Ltd.
Valuation and Qualifying Accounts
For the Years Ended December 31, 2017, 2016 and 2015

Description	Balance January 1,	Additions Charged to Costs and Expenses	Charged To Other Accounts	Deductions From Reserves	Balance December 31,
2017					
Allowance for doubtful receivables	$ 574	$ 77	$ —	$ (651)	$ —
Allowance for deferred tax assets	$ 87,517	$ 6,008	$ —	$ —	$ 93,525
2016					
Allowance for doubtful receivables	$ —	$ 574	$ —	$ —	$ 574
Allowance for deferred tax assets	$ 116,541	$ (29,024)	$ —	$ —	$ 87,517
2015					
Allowance for doubtful receivables	$ —	$ —	$ —	$ —	$ —
Allowance for deferred tax assets	$ 75,941	$ 40,600	$ —	$ —	$ 116,541

Schedules other than Schedule I and Schedule II have been omitted because they are not applicable or the required information is presented in the consolidated financial statements or the notes to consolidated financial statements.

(3) Exhibits

See “Index to Exhibits” on page 141 for a description of the exhibits filed as part of this report.

Item 16. Form 10-K Summary

None

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

KOSMOS ENERGY LTD.

Date: February 26, 2018 By: /s/ Thomas P. Chambers
Thomas P. Chambers
Senior Vice President and Chief Financial Officer

Table of Contents

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

Signature	Title	Date
/s/ Andrew G. Inglis Andrew G. Inglis	Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)	February 26, 2018
/s/ Brian F. Maxted Brian F. Maxted	Director and Chief Exploration Officer	February 26, 2018
/s/ Thomas P. Chambers Thomas P. Chambers	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2018
/s/ Paul M. Nobel Paul M. Nobel	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 26, 2018
/s/ Yves-Louis Darricarrére Yves-Louis Darricarrére	Director	February 26, 2018
/s/ Sir Richard B. Dearlove Sir Richard B. Dearlove	Director	February 26, 2018
/s/ David I. Foley David I. Foley	Director	February 26, 2018
/s/ David B. Krieger David B. Krieger	Director	February 26, 2018
/s/ Joseph P. Landy Joseph P. Landy	Director	February 26, 2018
/s/ Adebayo O. Ogunlesi Adebayo O. Ogunlesi	Director	February 26, 2018
/s/ Chris Tong Chris Tong	Director	February 26, 2018
/s/ Christopher A. Wright Christopher A. Wright	Director	February 26, 2018

Table of Contents

INDEX OF EXHIBITS

Exhibit Number	Description of Document
	Governing Documents
3.1	Certificate of Incorporation of the Company (filed as Exhibit 3.1 to the Company's Registration Statement on Form S 1/A filed March 23, 2011 (File No. 333 171700), and incorporated herein by reference).
3.2	Memorandum of Association of the Company (filed as Exhibit 3.2 to the Company's Registration Statement on Form S 1/A filed March 23, 2011 (File No. 333 171700), and incorporated herein by reference).
3.3	Bye laws of the Company (filed as Exhibit 4 to the Company's Registration Statement on Form 8 A filed May 6, 2011 (File No. 001 35167), and incorporated herein by reference).
4.1	Specimen share certificate (filed as Exhibit 4.1 to the Company's Registration Statement on Form S 1/A filed April 25, 2011 (File No. 333 171700), and incorporated herein by reference).
	Operating Agreements
	Ghana
10.1	Petroleum Agreement in respect of West Cape Three Points Block Offshore Ghana dated July 22, 2004 among the GNPC, Kosmos Ghana and the E.O. Group (filed as Exhibit 10.1 to the Company's Registration Statement on Form S 1/A filed March 3, 2011 (File No. 333 171700), and incorporated herein by reference).
10.2	Operating Agreement in respect of West Cape Three Points Block Offshore Ghana dated July 27, 2004 between Kosmos Ghana and E.O. Group (filed as Exhibit 10.2 to the Company's Registration Statement on Form S 1/A filed March 3, 2011 (File No. 333 171700), and incorporated herein by reference).
10.3	Petroleum Agreement in respect of the Deepwater Tano Contract Area dated March 10, 2006 among GNPC, Tullow Ghana, Sabre and Kosmos Ghana (filed as Exhibit 10.3 to the Company's Registration Statement on Form S 1/A filed March 3, 2011 (File No. 333 171700), and incorporated herein by reference).
10.4	Joint Operating Agreement in respect of the Deepwater Tano Contract Area, Offshore Ghana dated August 14, 2006, among Tullow Ghana, Sabre Oil and Gas Limited, and Kosmos Ghana (filed as Exhibit 10.4 to the Company's Registration Statement on Form S 1/A filed March 3, 2011 (File No. 333 171700), and incorporated herein by reference).
10.5	Assignment Agreement in respect of the Deepwater Tano Block dated September 1, 2006, among Anadarko WCTP and Kosmos Ghana (filed as Exhibit 10.5 to the Company's Registration Statement on Form S 1/A filed March 3, 2011 (File No. 333 171700), and incorporated herein by reference).
10.6	Unitization and Unit Operating Agreement covering the Jubilee Field Unit located offshore the Republic of Ghana dated July 13, 2009, among GNPC, Tullow, Kosmos Ghana, Anadarko WCTP, Sabre and E.O. Group (filed as Exhibit 10.6 to the Company's Registration Statement on Form S 1/A filed March 3, 2011 (File No. 333 171700), and incorporated herein by reference).
10.7	Settlement Agreement, dated December 18, 2010 among Kosmos Ghana, Ghana National Petroleum Corporation and the Government of the Republic of Ghana (filed as Exhibit 10.32 to the Company's Registration Statement on Form S 1/A filed April 14, 2011 (File No. 333 171700), and incorporated herein by reference).
	Morocco
10.8	Petroleum Agreement Regarding the Exploration for Exploitation of Hydrocarbons among Office National Des Hydrocarbures Et Des Mines acting on behalf of the Kingdom of Morocco, Kosmos Energy Deepwater Morocco and Canamens Energy Morocco SARL in the area of interest named "Essaouira Offshore" dated September 9, 2011 (filed as Exhibit 10.12 to the Company's Quarterly Report on Form 10 Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.9	Deed of Assignment in Petroleum Agreement for the Exploration for and Exploitation of Hydrocarbons in the zone of interest named "Essaouira Offshore" between Canamens Energy Morocco SARL and Kosmos Energy Deepwater Morocco dated December 19, 2012 (filed as Exhibit 10.13 to the Company's Quarterly Report on Form 10 Q for the quarter ended September 30, 2013, and incorporated herein by reference).
	Sao Tome and Principe

10.10	Production Sharing Contract relating to Block 5 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe and Equator Exploration STP Block 5 Limited dated April 18, 2012 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10 Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.11	Amendment No. 1, dated November 24, 2014, to the Production Sharing Contract relating to Block 5 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe and Equator Exploration STP Block 5 Limited dated April 18, 2012 (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).

Table of Contents

Exhibit Number	Description of Document
10.12	Amendment No. 2, dated September 15, 2015, to the Production Sharing Contract relating to Block 5 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe and Equator Exploration STP Block 5 Limited dated April 18, 2012 (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.13	Deed of Assignment relating to Block 5 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe, Equator Exploration STP Block 5 Limited and Kosmos Energy Sao Tome and Principe dated February 19, 2016 (filed as Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.14	Amendment No. 3, dated February 19, 2016, to the Production Sharing Contract relating to Block 5 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe, Equator Exploration STP Block 5 Limited and Kosmos Energy Sao Tome and Principe dated April 18, 2012 (filed as Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.15	Deed of Assignment relating to Block 5 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe, Equator Exploration STP Block 5 Limited, Galp Energia São Tomé e Príncipe, Unipessoal, LDA and Kosmos Energy Sao Tome and Principe dated December 13, 2016 (filed as Exhibit 10.16 to the Company's Annual Report on Form 10-K of the year ended December 31, 2016, and incorporated herein by reference).
10.16	Production Sharing Contract relating to Block 6 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe and Galp Energia São Tomé e Príncipe, Unipessoal, LDA dated October 26, 2015 (filed as Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.17	Addendum, dated November 9, 2015, to the Production Sharing Contract relating to Block 6 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe and Galp Energia São Tomé e Príncipe, Unipessoal, LDA dated October 26, 2015 (filed as Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.18	Deed of Assignment relating to Block 6 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe, Galp Energia São Tomé e Príncipe, Unipessoal, LDA and Kosmos Energy Sao Tome and Principe dated November 9, 2015 (filed as Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.19	Production Sharing Contract relating to Block 11 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe and ERHC Energy EEZ, LDA dated July 23, 2014 (filed as Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.20	Deed of Assignment relating to Block 11 Offshore Sao Tome between EHRC Energy EEZ, LDA and Kosmos Energy Sao Tome and Principe dated October 16, 2015 (filed as Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.21	First Addendum, dated December 17, 2015, to the Production Sharing Contract relating to Block 11 Offshore Sao Tome between the Democratic Republic of Sao Tome and Kosmos Energy Sao Tome and Principe dated July 23, 2014 (filed as Exhibit 10.11 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.22	Deed of Assignment relating to Block 11 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe, Galp Energia São Tomé e Príncipe, Unipessoal, LDA and Kosmos Energy Sao Tome and Principe dated December 13, 2016 (filed as Exhibit 10.23 to the Company's Annual Report on Form 10-K of the year ended December 31, 2016, and incorporated herein by reference).
10.23	Production Sharing Contract relating to Block 12 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe and Equator Exploration STP Block 12 Limited dated February 19, 2016 (filed as

	Exhibit 10.12 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.24	Deed of Assignment relating to Block 12 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe, Equator Exploration STP Block 12 Limited and Kosmos Energy Sao Tome and Principe dated March 31, 2016 (filed as Exhibit 10.13 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.25	First Amendment, dated March 31, 2016, to the Production Sharing Contract between the Democratic Republic of Sao Tome and Principe, Equator Exploration STP Block 12 Limited and Kosmos Energy Sao Tome and Principe dated February 19, 2016 (filed as Exhibit 10.14 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.26	Deed of Assignment relating to Block 12 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe, Equator Exploration STP Block 12 Limited, Galp Energia São Tomé e Príncipe, Unipessoal, LDA and Kosmos Energy Sao Tome and Principe dated December 13, 2016 (filed as Exhibit 10.27 to the Company's Annual Report on Form 10-K of the year ended December 31, 2016, and incorporated herein by reference).
	Senegal

Table of Contents

Exhibit Number	Description of Document
10.27	Hydrocarbon Exploration and Production Sharing Contract for the Cayar Offshore Profond between the Republic of Senegal and Petro Tim Limited and Societe des Petroles du Senegal dated January 17, 2012 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10 Q for the quarter ended September 30, 2014, and incorporated herein by reference).
10.28	Hydrocarbon Exploration and Production Sharing Contract for the Saint Louis Offshore Profond between the Republic of Senegal and Petro Tim Limited and Societe des Petroles du Senegal dated January 17, 2012 (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10 Q for the quarter ended September 30, 2014, and incorporated herein by reference).
10.29	Deed of Transfer between La Societe Des Petroles Du Senegal (Petrosen), Timis Corporation Limited and Kosmos Energy Senegal concerning the Hydrocarbons Exploration and Production Sharing Contracts and Joint Operating Agreements covering the Cayar Offshore and Saint Louis Offshore Permits dated August 25, 2014 (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10 Q for the quarter ended September 30, 2014, and incorporated herein by reference).
10.30	Sale and Purchase Agreement relating to the sale and purchase of shares in Kosmos BP Senegal Limited (formerly Normandy Ventures Limited) between BP Indonesia Oil Terminal Investment Limited and Kosmos Energy Senegal dated December 15, 2016 (filed as Exhibit 10.31 to the Company's Annual Report on Form 10-K of the year ended December 31, 2016, and incorporated herein by reference).
	Suriname
10.31	Production Sharing Contract for Petroleum Exploration, Development and Production relating to Block 42 Offshore Suriname between Staatsolie Maatshappij Suriname N.V. and Kosmos Energy Suriname dated December 13, 2011 (filed as Exhibit 10.20 to the Company's Quarterly Report on Form 10 Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.32	Production Sharing Contract for Petroleum Exploration, Development and Production relating to Block 45 Offshore Suriname between Staatsolie Maatshappij Suriname N.V. and Kosmos Energy Suriname dated December 13, 2011 (filed as Exhibit 10.21 to the Company's Quarterly Report on Form 10 Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.33	Deed of Assignment and Transfer relating to Blocks 42 and 45 Offshore Suriname between Kosmos Energy Suriname and Chevron Suriname Exploration Limited dated May 31, 2012 (filed as Exhibit 10.22 to the Company's Quarterly Report on Form 10 Q for the quarter ended September 30, 2013, and incorporated herein by reference).
	Mauritania
10.34	Exploration and Production Contract between The Islamic Republic of Mauritania and Kosmos Energy Mauritania (Block C8) dated April 5, 2012 (filed as Exhibit 10.17 to the Company's Quarterly Report on Form 10 Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.35	Exploration and Production Contract between The Islamic Republic of Mauritania and Kosmos Energy Mauritania (Bloc C12) dated April 5, 2012 (filed as Exhibit 10.18 to the Company's Quarterly Report on Form 10 Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.36	Exploration and Production Contract between The Islamic Republic of Mauritania and Kosmos Energy Mauritania (Bloc C13) dated April 5, 2012 (filed as Exhibit 10.19 to the Company's Quarterly Report on Form 10 Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.37	Deed of Novation and Assignment and Transfer dated March 25, 2015 between Kosmos Energy Mauritania, Chevron Mauritania Exploration Limited and SMHPM in relation to Block C8 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K dated March 25, 2015, and incorporated herein by reference).
10.38	Deed of Novation and Assignment and Transfer dated March 25, 2015 between Kosmos Energy Mauritania, Chevron Mauritania Exploration Limited and SMHPM in relation to Block C12 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K dated March 25, 2015, and incorporated herein by reference).
10.39	

	Deed of Novation and Assignment and Transfer dated March 25, 2015 between Kosmos Energy Mauritania, Chevron Mauritania Exploration Limited and SMHPM in relation to Block C13 (filed as Exhibit 10.3 to the Company’s Current Report on Form 8-K dated March 25, 2015, and incorporated herein by reference).
10.40	Exploration and Production Contract between The Islamic Republic of Mauritania and Kosmos Energy Mauritania (Bloc C6) dated October 11, 2016 (filed as Exhibit 10.41 to the Company's Annual Report on Form 10-K of the year ended December 31, 2016, and incorporated herein by reference).
10.41	Farmout Agreement Relating to Blocks C6, C8, C12 and C13 Offshore Mauritania between BP Exploration (West Africa) Limited and Kosmos Energy Mauritania dated December 15, 2016 (filed as Exhibit 10.42 to the Company's Annual Report on Form 10-K of the year ended December 31, 2016, and incorporated herein by reference).
10.42*	Exploration and Production Contract between The Islamic Republic of Mauritania and Tullow Mauritania Limited (Bloc C18) dated May 17, 2012.

Table of Contents

Exhibit Number	Description of Document
	Equatorial Guinea
10.43*	Share Sale and Purchase Agreement relating to the sale and purchase of shares in Hess International Petroleum, Inc. between Hess Equatorial Guinea Investments Limited, Hess Corporation, Kosmos Energy Equatorial Guinea, Kosmos Energy Operating and Trident Energy E.G. Operations, Ltd. dated October 23, 2017.
	Cote d'Ivoire
10.44*	Hydrocarbons Production Sharing Agreement between The Republic of Cote d'Ivoire, BP Exploration Operating Company Limited and Kosmos Energy Cote d'Ivoire (Block CI-526) dated December 21, 2017.
10.45*	Hydrocarbons Production Sharing Agreement between The Republic of Cote d'Ivoire, BP Exploration Operating Company Limited and Kosmos Energy Cote d'Ivoire (Block CI-602) dated December 21, 2017.
10.46*	Hydrocarbons Production Sharing Agreement between The Republic of Cote d'Ivoire, BP Exploration Operating Company Limited and Kosmos Energy Cote d'Ivoire (Block CI-603) dated December 21, 2017.
10.47*	Hydrocarbons Production Sharing Agreement between The Republic of Cote d'Ivoire, BP Exploration Operating Company Limited and Kosmos Energy Cote d'Ivoire (Block CI-707) dated December 21, 2017.
10.48*	Hydrocarbons Production Sharing Agreement between The Republic of Cote d'Ivoire, BP Exploration Operating Company Limited and Kosmos Energy Cote d'Ivoire (Block CI-708) dated December 21, 2017.
	Financing Agreements
10.49	Intercreditor Agreement, dated March 28, 2011 among BNP Paribas, Kosmos Finance International, Kosmos Operating, Kosmos International, Kosmos Development, Kosmos Ghana and the various financial institutions and others party thereto (filed as Exhibit 10.20 to the Company's Registration Statement on Form S 1/A filed April 25, 2011 (File No. 333 171700), and incorporated herein by reference).
10.50	Facility Agreement, dated February 17, 2012, among Kosmos Energy Finance International, Kosmos Energy Operating, Kosmos Energy International, Kosmos Energy Development, Kosmos Energy Ghana HC and International Finance Corporation (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10 Q for the quarter ended March 31, 2012, and incorporated herein by reference).
10.51	Deed of Transfer and Amendment, dated February 17, 2012, among Kosmos Energy Finance International, Kosmos Energy Operating, Kosmos Energy International, Kosmos Energy Development, Kosmos Energy Ghana HC, BNP Paribas, Citibank N.A., Credit Suisse International, Société Générale London Branch and International Finance Corporation (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10 Q for the quarter ended March 31, 2012, and incorporated herein by reference).
10.52	Charge on Cash Deposits and Account Bank Agreement, dated as of July 3, 2013, among Kosmos Energy Credit International and Societe Generale, London Branch, as Security Agent and Account Bank (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10 Q for the quarter ended June 30, 2013, and incorporated herein by reference).
10.53	Deed of Amendment and Restatement relating to the Revolving Credit Facility Agreement, dated March 14, 2014, among Kosmos Energy Ltd., as Original Borrower, certain of its subsidiaries listed therein, as Original Guarantors, Standard Chartered Bank, as Facility Agent, BNP Paribas, as Security and Intercreditor Agent, and the financial institutions listed therein, as Original Lenders (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10 Q for the quarter ended March 31, 2014, and incorporated herein by reference).
10.54	Amendment Letter, dated June 8, 2015, supplemental to and amending the Revolving Credit Facility Agreement, dated March 14, 2014, among Kosmos Energy Ltd., as Original Borrower, certain of its subsidiaries listed therein, as Original Guarantors, Standard Chartered Bank, as Facility Agent, BNP Paribas, as Security and Intercreditor Agent, and the financial institutions listed therein, as Original Lenders (filed as Exhibit 1.1 to the Company's Current Report on Form 8-K dated June 8, 2015, and incorporated herein by reference).
10.55	Deed of Amendment and Restatement relating to the Facility Agreement and a Charge over Shares in Kosmos Energy Operating, dated March 14, 2014, among Kosmos Energy Finance International, as Original

	Borrower, Kosmos Energy Operating, Kosmos Energy International, Kosmos Energy Development and Kosmos Energy Ghana HC, as Original Guarantors, Kosmos Energy Holdings, as Chargor, and BNP Paribas, as Facility Agent and Security Agent (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10 Q for the quarter ended March 31, 2014, and incorporated herein by reference).
10.56	Indenture, dated as of August 1, 2014, among the Company, Kosmos Energy Operating, Kosmos Energy International, Kosmos Energy Development, Kosmos Energy Ghana HC and Kosmos Energy Finance International, Wilmington Trust, National Association, as trustee, transfer agent, registrar and paying agent and Banque Internationale à Luxembourg S.A., as Luxembourg listing agent, transfer agent and paying agent (including the Form of Notes) (filed as Exhibit 4.1 to the Company's Current Report on Form 8 K filed August 4, 2014 (File No. 001 35167), and incorporated herein by reference).

141

Table of Contents

Exhibit Number	Description of Document
10.57	KEL Intercreditor and Security Sharing Agreement, dated as of August 1, 2014, among the Company, BNP Paribas, as security and intercreditor agent, Standard Chartered Bank, as RCF Agent and Wilmington Trust, National Association, as trustee, transfer agent, registrar and paying agent (filed as Exhibit 4.2 to the Company's Current Report on Form 8 K filed August 4, 2014 (File No. 001 35167), and incorporated herein by reference).
	Agreements with Shareholders and Directors
10.58	Form of Director Indemnification Agreement (filed as Exhibit 10.27 to the Company's Registration Statement on Form S 1/A filed April 14, 2011 (File No. 333 171700), and incorporated herein by reference).
10.59	Shareholders Agreement, dated as of May 10, 2011, among Kosmos Energy Ltd. and the other parties signatory thereto (filed as Exhibit 9.1 to the Company's Annual Report on Form 10 K for the year ended December 31, 2012, and incorporated herein by reference).
10.60	Registration Rights Agreement, dated as of October 7, 2009, among Kosmos Energy Holdings and the other parties signatory thereto (filed as Exhibit 10.32 to the Company's Annual Report on Form 10 K for the year ended December 31, 2012, and incorporated herein by reference).
10.61	Joinder Agreement to the Registration Rights Agreement, dated as of May 10, 2011, among Kosmos Energy Ltd. and the other parties signatory thereto (filed as Exhibit 10.33 to the Company's Annual Report on Form 10 K for the year ended December 31, 2012, and incorporated herein by reference).
10.62	Amendment No. 1 to the Registration Rights Agreement, dated as of February 8, 2013, among Kosmos Energy Ltd. and the other parties signatory thereto (filed as Exhibit 10.34 to the Company's Annual Report on Form 10 K for the year ended December 31, 2012, and incorporated herein by reference).
	Management Contracts/Compensatory Plans or Arrangements
10.63†	Long Term Incentive Plan (filed as Exhibit 99.1 to the Company's Registration Statement on Form S 8 filed May 16, 2011 (File No. 333 174234), and incorporated herein by reference).
10.64†	Long Term Incentive Plan (amended and restated as of January 23, 2015) (filed as Exhibit 99 to the Company's Registration Statement on Form S-8 filed October 2, 2015 (File No. 333-207259), and incorporated herein by reference).
10.65†	Long Term Incentive Plan (amended and restated as of January 23, 2017) (filed as Exhibit 10.64 to the Company's Annual Report on Form 10-K for the year ended December 31, 2016, and incorporated herein by reference).
10.66†	Annual Incentive Plan (filed as Exhibit 10.22 to the Company's Registration Statement on Form S 1/A filed March 30, 2011 (File No. 333 171700), and incorporated herein by reference).
10.67†	Form of Restricted Stock Award Agreement (Service-Vesting) (filed as Exhibit 10.50 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, and incorporated herein by reference).
10.68†	Form of Restricted Stock Award Agreement (Performance-Vesting) (filed as Exhibit 10.51 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, and incorporated herein by reference).
10.69†	Form of RSU Award Agreement (Service-Vesting) (filed as Exhibit 10.52 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, and incorporated herein by reference).
10.70†	Form of RSU Award Agreement (Performance-Vesting) (filed as Exhibit 10.13 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2015, and incorporated herein by reference).
10.71†	Form of Directors RSU Award Agreement (Service-Vesting) (filed as Exhibit 10.54 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, and incorporated herein by reference).
10.72†	Offer Letter, dated November 2, 2014, between Kosmos Energy, LLC and Michael Anderson (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10 Q for the quarter ended March 31, 2017, and incorporated herein by reference).
10.73†	Offer Letter, dated September 1, 2011, between Kosmos Energy, LLC and Jason Doughty (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10 Q for the quarter ended June 30, 2014, and incorporated herein by reference).

10.74†	Offer Letter, dated May 22, 2013, between Kosmos Energy, LLC and Christopher Ball (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10 Q for the quarter ended June 30, 2014, and incorporated herein by reference).
10.75†	Offer Letter, dated January 10, 2014, between Kosmos Energy, LLC and Andrew Inglis (filed as Exhibit 10.58 to the Company's Annual Report on Form 10 K for the year ended December 31, 2013, and incorporated herein by reference).
10.76†	Assignment Agreement, dated April 16, 2014, between Kosmos Energy, LLC and Brian F. Maxted (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10 Q for the quarter ended June 30, 2014, and incorporated herein by reference).

Table of Contents

Exhibit Number	Description of Document
10.77†	Offer Letter, dated October 16, 2014, between Kosmos Energy, LLC and Thomas P. Chambers (filed as Exhibit 10.60 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, and incorporated herein by reference).
10.78†	Offer Letter, dated February 11, 2008, between Kosmos Energy, LLC and Eric Haas (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, and incorporated herein by reference).
10.79†	Kosmos Energy Ltd. Change in Control Severance Policy for U.S. Employees, dated December 19, 2013 (filed as Exhibit 10.66 to the Company's Annual Report on Form 10 K for the year ended December 31, 2013, and incorporated herein by reference).
	Other Exhibits
14.1	Code of Business Conduct and Ethics (filed as Exhibit 14.1 to the Company's Annual Report on Form 10 K for the year ended December 31, 2011, and incorporated herein by reference).
21.1*	List of Subsidiaries.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Ryder Scott Company, L.P.
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002.
99.1*	Report of Ryder Scott Company, L.P.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.

* Filed herewith.

** Furnished herewith.

† Management contract or compensatory plan or arrangement.