Kosmos Energy Ltd.
Form 10-K
March 01, 2019

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, 2018

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)

Delaware (State or other jurisdiction of incorporation or organization)	98 0686001 (I.R.S. Employer Identification No.)
8176 Park Lane Dallas, Texas (Address of principal executive offices)	75231 (Zip Code)

Registrant's telephone number, including area code: +1 214 445 9600
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered:
Common Stock $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.

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

(Do not check if a smaller reporting 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 stock held by non affiliates, based on the per share closing price of the registrant's common stock as of the last business day of the registrant's most recently completed second fiscal quarter was $1,954,943,075.

The number of the registrant's Common Stock outstanding as of February 15, 2019 was 401,252,135.

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, 2018.

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

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Unless otherwise stated in this report, references to “Kosmos,” “we,” “us” or “the company” refer to Kosmos Energy Ltd. and its subsidiaries. On December 28, 2018, we changed our jurisdiction of incorporation from Bermuda to the State of Delaware, which we refer to herein as the Redomestication. All references to “Kosmos,” “we,” “us” or “the company” on or before December 28, 2018 refer to Kosmos Energy Ltd., an exempted company incorporated pursuant to the laws of Bermuda, and its subsidiaries. All such references after December 28, 2018 refer to Kosmos Energy Ltd., a Delaware corporation, and its subsidiaries. In addition, all references to “common stock” on or before December 28, 2018 refer to the common shares of Kosmos Energy Ltd. prior to the Redomestication, and all such references after December 28, 2028 refer to the common stock of Kosmos Energy Ltd. after the Redomestication. For additional detail, please see “Item 1. Business—Corporate Information.”

In addition, we have provided definitions for some of the industry terms used in this report in the “Glossary and Selected Abbreviations” beginning on page 3.

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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" or "Unsuccessful well"	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 and includes Last Twelve Months ("LTM") EBITDAX for any acquisitions and excludes LTM EBITDAX for any divestitures.
"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/or for taking on a portion of future costs 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 future costs and/or other work as a condition of the assignment.

“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.
"FLNG"	Floating liquified natural gas.
“FPS”	Floating production system.
“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.
“MBoe”	Thousand barrels of oil equivalent.
“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.
"MMBtu"	Million British thermal units
“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	Those proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

reserves”	
“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.

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“Stratigraphy”	The study of the composition, relative ages and distribution of layers of sedimentary rock.
“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.
“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.

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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 to us by the governments of the countries in which we operate (or their respective national oil companies) or any other federal, state or local governments or authorities;
- 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, natural gas and NGL 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;

- our vulnerability to severe weather events, including tropical storms and hurricanes in the Gulf of Mexico;
- 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, performance bonds 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.

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PART I
Item 1. Business
General

Kosmos is a full-cycle deepwater independent oil and gas exploration and production company focused along the Atlantic Margins. Our key assets include production offshore Ghana, Equatorial Guinea and U.S. Gulf of Mexico, as well as a world-class gas development offshore Mauritania and Senegal. We also maintain a sustainable exploration program balanced between proven basin infrastructure-led exploration (Equatorial Guinea and U.S. Gulf of Mexico), emerging basins (Mauritania, Senegal and Suriname) and frontier basins (Cote d'Ivoire, Namibia and Sao Tome and Principe). 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 systems in West Africa. In its relatively brief history the Company has successfully opened two new hydrocarbon basins through the discovery of the Jubilee field offshore Ghana in 2007 and the Greater Tortue Ahmeyim development (which includes the Ahmeyim and Guembeul-1 discoveries offshore Mauritania and Senegal in 2015 and 2016, respectively). Jubilee was one of the largest oil discoveries worldwide in 2007 and is considered one of the largest finds offshore West Africa during that decade. First oil production was delivered just 42 months after initial discovery, a record for a deepwater development in this water depth in West Africa. 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.
Over the last two years, our business strategy has evolved to include production enhancing infill drilling and well work as well as infrastructure-led exploration. This strategic evolution was initially enabled by our acquisition of the Ceiba Field and Okume Complex assets offshore Equatorial Guinea in October 2017 together with access to surrounding exploration licenses, and bolstered by the September 2018 acquisition of Deep Gulf Energy (together with its subsidiaries "DGE"), a deepwater company operating in the U.S. Gulf of Mexico, which further enhanced our production, exploitation and infrastructure-led exploration capabilities.

Our Business Strategy
As a full-cycle E&P company, our mission is to deliver production and free cash flow from a portfolio rich in opportunities through a disciplined allocation of capital and optimal portfolio management for the benefit of our shareholders.

Our business strategy is designed to accomplish this mission by focusing on three key objectives: (1) maximize the value of our producing assets; (2) progress our discovered resources toward project sanction and into proved reserves, production, and cash flow through efficient appraisal and development; and (3) add new resources through a consistently active low cost exploration program. We are focused on increasing production, cash flows and reserves from our producing assets in Equatorial Guinea, Ghana, and the U.S. Gulf of Mexico. In Mauritania and Senegal, we are progressing our Greater Tortue Ahmeyim development with the objective of reaching first gas in the first half of 2022, as well as advancing our other discoveries towards a final investment decision. We also have a large inventory of leads and prospects in our exploration portfolio along the Atlantic Margins, both infrastructure-led and basin opening opportunities, which we plan to continue to mature for future drilling, providing us access to asymmetric growth potential in the coming years.
Grow cash flow, proved reserves and production through exploitation, development, infrastructure-led exploration and basin opening exploration activities
In the near term, we plan to grow cash flow, proved reserves and production by further exploiting our fields offshore Ghana, U.S. Gulf of Mexico, and Equatorial Guinea. In Ghana, we plan to continue drilling additional development and production wells at both the Jubilee and TEN fields in 2019. In the U.S. Gulf of Mexico we plan to continue infill

drilling on existing fields, drilling infrastructure-led exploration targets, and progressing the development of the Nearly Headless Nick discovery via subsea tieback to existing infrastructure. In Equatorial Guinea our activity set is expanding beyond production optimization projects utilizing electrical submersible pumps to include infrastructure-led exploration which, if successful, can be brought online quickly via subsea tieback to existing infrastructure. In addition, we have sanctioned the first phase of the Greater Tortue Ahmeyim development offshore Mauritania and Senegal, which defines the timing and path to first gas. Beyond Greater Tortue Ahmeyim, growth could also be realized through the development of all or a portion of our other discoveries in Mauritania and Senegal. Our basin opening exploration efforts continue to be a significant portion of the portfolio. We believe the prospects and leads offshore Mauritania, Senegal, Sao Tome and Principe, Cote d'Ivoire, Namibia, and Suriname provide favorable opportunities to create

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substantial future growth and value through exploration drilling. During 2019, we plan to further test the potential of previous discoveries in Mauritania and Senegal and drill five infrastructure-led prospects in Equatorial Guinea and the U.S. Gulf of Mexico. Given the potential size of these prospects and leads, we believe that exploratory and appraisal success in our operating areas could significantly add to our growth profile.

Focus on optimally developing our discoveries to initial production

Our approach to development is designed to deliver first production on an accelerated timeline, leverage early learnings to improve future outcomes and maximize returns. In certain circumstances, we believe a phased approach can be employed to optimize full field development. A phased approach 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.

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 Ahmeyim development is also expected to be developed in an accelerated, phased approach consistent with our business strategy. This is anticipated to result in first gas seven years after initial discovery, which feeds the market at a potentially optimal time as demand is expected to outpace supply.

Kosmos Exploration Approach - A balance of basin opening and infrastructure-led

Kosmos' exploration philosophy, which is traditionally basin opening based, is deeply rooted in a fundamental, geologic approach geared toward the identification of under explored or overlooked petroleum systems. 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: (i) long term contract durations to enable the "right" exploration program to be executed, (ii) play type diversity to provide multiple exploration concept options, (iii) prospect dependency to enhance the chance of replicating success, and (iv) sufficiently attractive fiscal terms to maximize the commercial viability of discovered hydrocarbons. This type of exploration provides the portfolio with access to asymmetric growth possibilities. 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 for all new areas and is a key strength of Kosmos.

Our exploration approach has evolved to include infrastructure-led exploration. This shorter-cycle approach, which can typically deliver first production in less than 18 months, is aimed at areas where we have existing production and where there is sufficient infrastructure capacity to enable the development of new discoveries via subsea tieback. Acquisitions of the Ceiba Field and Okume Complex in Equatorial Guinea together with access to surrounding exploration licenses and the DGE assets in the Gulf of Mexico have added to the inventory of infrastructure-led exploration given their attractive acreage positions within proximity of existing infrastructure that has excess capacity available. This opens a new growth area with attractive economics in areas with high margin production that complements the basin opening exploration program. It also allows shared learnings across the portfolio.

Build the right strategic partnerships with complementary capabilities

As a full-cycle E&P company, part of our strategy is to optimize our portfolio at appropriate times for our exploration and development projects. One of the ways to accomplish this is to partner with high-quality industry players with world class complementary capabilities. This strategy is designed to ensure that the relative 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") and Royal Dutch Shell ("Shell") 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 costs and increase return on investment.

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For example, in 2017 we formed an alliance with a subsidiary of BP. This alliance broadened the relationship that previously covered new venture opportunities in Mauritania, Senegal and The Gambia to create an Atlantic Margin explorer-developer partnership. The alliance combines Kosmos' regional exploration knowledge and capability with BP's deepwater development expertise to execute a selective, basin opening exploration strategy in the Atlantic Margin.

During the fourth quarter of 2018, Kosmos entered into an additional strategic exploration alliance with a subsidiary of Shell to jointly explore in Southern West Africa. Initially, the alliance will focus on Namibia where Kosmos has completed a farm-in to Shell's acreage in PEL 39, and Sao Tome & Principe where we have entered into exclusive negotiations for Shell to take an interest in Kosmos' acreage in Blocks 5, 6, 11 and 12. As part of the alliance, the two companies will also jointly evaluate opportunities in adjacent geographies. This alliance is consistent with Kosmos' strategy of partnering with supermajors to leverage complementary skill sets. Shell has deep expertise in carbonate plays, while Kosmos brings significant knowledge of the Cretaceous in West Africa. Furthermore, by working with Shell, Kosmos has a partner with the expertise to efficiently move exploration successes through the development stage.

During the first quarter of 2019, Kosmos expanded its relationship with BP to grow Kosmos' footprint in the deepwater U.S. Gulf of Mexico. The venture includes the evaluation of 18 jointly owned leases in the Garden Banks area and an opportunity to earn an interest in three additional blocks in other areas of the deepwater U.S. Gulf of Mexico. This transaction will allow both companies to leverage complementary skill sets to execute farm-in projects around infrastructure. Kosmos will be designated operator and plans to commence drilling operations on the first well in 2019.

During the first quarter of 2019, Kosmos executed a farm-in agreement with Chevron covering the right to earn an interest in a strategic block in the deepwater U.S. Gulf of Mexico. This agreement allows Kosmos another opportunity to execute its deepwater U.S. Gulf of Mexico strategy of lower risk prospects with the potential for subsea development near existing midstream infrastructure. Kosmos will be designated operator and plans to commence drilling operations in 2019.

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, developing and producing new fields and optimizing production from existing 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 ideas that create and maximize value and free cash flow.

Maintain Financial Discipline

Execution of our strategy requires us to maintain a conservative financial approach with a strong balance sheet, ample liquidity, a commitment to low leverage and the ability to maintain significant headroom on our debt covenants. Typically, we fund exploration and development activities from a combination of operating cash flows, debt and partner carries.

As of December 31, 2018, our net leverage ratio was just slightly over 2.0 times, largely the result of borrowing for the Gulf of Mexico acquisition. Our liquidity, after consideration of the additional RBL Facility commitments which became effective in January 2019, was approximately $0.6 billion available to fund our opportunities. When we do increase our net leverage as we did in 2018 with the U.S. Gulf of Mexico acquisition, we develop a well thought out plan to bring leverage back down.

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, with the goal to protect against the downside price scenario while still retaining partial exposure to the upside. As of December 31, 2018, we have hedged positions covering 15.6 million barrels of oil production from 2019 through 2020. We also maintain insurance to partially protect against loss of production revenues from our producing assets.

During 2018, Kosmos generated approximately $260.5 million of cash flow from operations.

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Operations by Geographic Area

We currently have operations in Africa and the Americas. Presently, our operating revenues are generated from our operations offshore U.S. Gulf of Mexico and Ghana. We also have an equity method investment generating revenues with operations offshore Equatorial Guinea. The following table provides a summary of certain key 2018 data for our geographic areas.

Geographic Area	Sales Volumes (Net to Kosmos)	Percentage of Total Sales Volumes		Revenue	Year-End Estimated Proved Reserves(1)	Percentage of Total Estimated Proved Reserves	
	(in MMboe)			(in thousands)	(in MMboe)		
Ghana	10.7	58	%	$ 739,070	89.7	54	%
U.S. Gulf of Mexico(2)	2.6	14		147,596	51.1	30	
Total Kosmos	13.3			886,666	140.8		
Equatorial Guinea(3)	5.2	28		360,650	26.6	16	
Total	18.5	100	%	1,247,316	167.4	100	%

(1) For information concerning our estimated proved reserves as of December 31, 2018, see "—Our Reserves."

(2) Represents contributions from the U.S. Gulf of Mexico after the acquisition date.

(3) Includes our 50% share from our equity method investment in Equatorial Guinea. Under the equity method of accounting, we only recognize our share of the net income of KTIPI as adjusted for our basis differential, which is recorded in (Gain) loss on equity method investments, net in the consolidated statement of operations. Effective as of January 1, 2019, our equity method investment in Equatorial Guinea was converted to an undivided interest in Block G.

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

Fields	License	Kosmos Participating Interest	Operator	Stage	License Expiration
Ghana(1)					
Jubilee	WCTP/DT (2)	24.1 % (2)	Tullow	Production	2034
TEN	DT	17.0 % (4)	Tullow	Production	2036
U.S. Gulf of Mexico(1)					
Barataria	MC 521	22.5 %	Kosmos	Production	(10)
Big Bend	MC 697 / 698 / 742	5.3 %	Fieldwood	Production	(10)
Don Larsen	EB 598	20.0 %	Anadarko	Production	(10)
Gladden	MC 800	20.0 %	W&T	Production	(10)
Kodiak	MC 727 / 771	29.1 %	Kosmos	Production	(10)
Marmalard	MC 255 / 300	11.8 %	LLOG	Production	(10)
Nearly Headless Nick	MC 387	22.0 %	LLOG	Development	(10)
Danny Noonan	EC 381 GB 463 / 506	Various (5)	Talos	Production	(10)
Odd Job	MC 214 / 215	Various (6)	Kosmos	Production	(10)
Sargent	GB 339	50.0 %	Kosmos	Production	(10)
SOB II	MC 431	11.8 %	LLOG	Production	(10)
S. Santa Cruz	MC 563	40.5 %	Kosmos	Production	(10)
Tornado	GC 281	35.0 %	Talos	Production	(10)
Mauritania					
Greater Tortue Ahmeyim	Block C8 (3)	29.0 % (7)	BP	Development	2049 (11)
Marsouin	Block C8	28.0 % (7)	BP	Appraisal	2019 (12)
Senegal					
Greater Tortue Ahmeyim	Saint Louis Offshore Profond (3)	29.0 % (8)	BP (8)	Development	2044 (11)
Teranga	Cayar Offshore Profond	30.0 % (8)	BP (8)	Appraisal	2021
Yakaar	Cayar Offshore Profond	30.0 % (8)	BP (8)	Appraisal	2021
Equatorial Guinea(1)					
Ceiba Field and Okume Complex	Block G	40.4 % (9)	Trident (9)	Production	2034

(1) For information concerning our estimated proved reserves as of December 31, 2018, 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 "Jubilee UUOA") in July 2009 with the Ghana National Petroleum Corporation ("GNPC") and the other block partners of each of these two blocks. The Jubilee 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.

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

(3) The Greater Tortue Ahmeyim Unit, 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. To optimize resource recovery in this field, we entered into a Unitization and Unit Operating

Agreement ("GTA UUOA") in February 2019 with the governments of Mauritania and Senegal. The GTA UUOA governs interests in and development of the Greater Tortue Ahmeyim Field and created the Greater Tortue Ahmeyim Unit from portions of the Mauritania Block C8 and the Senegal Saint Louis Offshore Profond areas.

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

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(5) Our interests in blocks EC 381, GB 463 and GB 506 are 30%, 15% and 30%, respectively.

(6) Our interests in blocks MC 214 and MC 215 are 61.1% and 54.9%, respectively.

(7) SMHPM has the option to acquire up to an additional 4% paying interests in a commercial development on Block C8. 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 owned a 50% interest in KTIPI which held 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 provided operational management and support to KTEGI, who is operator of the Ceiba Field and Okume Complex. Effective January 1, 2019, our outstanding shares in KTIPI were transferred to Trident Energy ("Trident") in exchange for a 40.375% undivided interest in the Ceiba Field and Okume Complex and Trident became the operator. As a result, our interest in the Ceiba Field and Okume Complex will be accounted for under the proportionate consolidation method of accounting going forward.

(10) Our U.S. Gulf of Mexico blocks are held by production/operations, and the lease periods extend as long as production/governmental approved operations continue on the relevant block.

(11) License expiration date can be extended by an additional ten years subject to certain conditions being met.

(12) License expiration date can be extended beyond the current exploration period upon completion of required work program and subject to additional work obligations.

Exploration License and Lease Areas

Country	Number of Blocks	Kosmos Average Participating Interest		Operator(s)	License Expiration Range	
Cote D'Ivoire	5	45.0%	(1)	Kosmos	2020	(8)
Equatorial Guinea	4	40.0%	(2)	Kosmos	2020-2021	(8)
Mauritania	5	25.4%	(3)	BP, Total	2019-2020	(8)
Namibia	1	45.0%	(4)	Shell	2019	(8)
Sao Tome and Principe	6	45.0%	(5)	Kosmos, BP, Galp	2019-2022	(8)
Senegal	2	30.0%	(6)	BP	2020-2021	
Suriname	2	41.7%	(7)	Kosmos	2020-2021	(8)
U.S. Gulf of Mexico	22	54.0%		Kosmos, Chevron, LLOG, Murphy	2019-2028	(9)

(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) 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) 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) Should a commercial discovery be made, NAMCOR's 10% carried participating interest during the exploration period may continue through first commercial production but must be reimbursed through production.

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(5) ANP-STP's carried interest may be converted to a full participating interest at any time. ANP-STP will reimburse any costs, expenses and any amount incurred on its behalf prior to the election.

(6) 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.

(7) Should a commercial discovery be made, Staatsolie has the option to participate up to 10% in Block 42 and up to 15% in Block 45 in each commercial discovery. Staatsolie will pay its portion of development and production costs in a commercial development in which it participates.

(8) License expiration date can be extended beyond the current exploration period upon completion of required work program and subject to additional work obligations.

(9) Our U.S. Gulf of Mexico blocks can be held by continued operations, and the lease periods extend as long as governmental approved operations continue on the relevant block.

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 Jubilee UUOA, the discovery area was unitized for purposes of joint development by the WCTP and DT Block partners.

The Jubilee Field is located approximately 60 kilometers offshore Ghana in water depths of approximately 1,000 to 1,800 meters, 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 initial phase provided subsea infrastructure capacity for additional production and injection wells to be drilled in future phases of development.

The GJFFDP was approved by the Government of Ghana 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.

The Government of Ghana completed the construction and connection of a gas pipeline in 2017 from the Jubilee Field to transport natural gas to the mainland for processing and sale. In the absence of 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 February 2016, the Jubilee Field operator identified an issue with the turret bearing of the FPSO Kwame Nkrumah. Kosmos and its partners completed the lifting and locking of the main turret bearing, and the rotation of the vessel to its final heading in the second half of 2018. Permanent spread mooring of the vessel is expected to be completed around mid-year 2019.

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 78,000 Bopd gross (18,800 Bopd net) during 2018.

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Tweneboa, Enyenra and Ntomme ("TEN")

The TEN fields are located in the western and central portions of the DT Block, approximately 48 kilometers offshore Ghana in water depths of approximately 1,000 to 1,700 meters. In November 2012, we submitted a declaration of commerciality and PoD over the TEN discoveries, and 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 Professor John Evans Atta Mills.

Similar to Jubilee, 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, 13 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.

First oil from the TEN fields was produced in August 2016. 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. In September 2017, International Tribunal of the Sea issued its final decision in the previously disclosed maritime boundary dispute between the Governments of Ghana and Cote d'Ivoire, which allowed drilling to resume in early 2018. These additional wells are expected to increase production towards FPSO capacity. Production from TEN in the year ended December 31, 2018 averaged approximately 64,500 Bopd gross (10,400 Bopd net).

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 commenced exporting gas to shore in the fourth quarter of 2018. However, the uptime of the gas processing facility in future periods is unknown. Our inability to continuously export associated natural gas in large quantities from the TEN fields could impact our oil production.

U.S. Gulf of Mexico

In September 2018, as part of the DGE transaction, Kosmos acquired: (i) a portfolio of producing assets that Kosmos can continue to exploit, (ii) infrastructure-led exploration growth assets, and (iii) a high-quality inventory of exploration prospects across the East Breaks, Garden Banks, Green Canyon and Mississippi Canyon areas. Our U.S. Gulf of Mexico assets averaged approximately 23,700 Boepd (net) (~81% oil) from twelve fields from the acquisition date through the end of 2018. We expanded our inventory through the U.S. Gulf of Mexico Lease Sale 251 in which we were awarded seven new deepwater blocks.

The following is a brief discussion of our key producing fields in the U.S. Gulf of Mexico.

Odd Job

The Odd Job field is producing through the Delta House FPS, operated by LLOG. The technical team initially identified the Middle Miocene sands at the Odd Job prospect using attribute analysis of a multi-client 3-D survey. These sands are currently producing through the Odd Job 215 #1 well and the Odd Job 215 #2 well. A third well, the Odd Job 214 #2 well, was drilled in 2018 and will be completed in the fourth quarter of 2019. A fourth exploration target in the field is a deeper Middle Miocene sand and is expected to be tested during the third quarter of 2019. The two currently producing wells achieved peak production of approximately 24,000 Boepd (gross), and net production from the acquisition date through the end of 2018 averaged approximately 5,900 Boepd.

Tornado

The Tornado field is producing from two Pliocene wells through the Helix Producer I, a ship-shaped, dynamically-positioned production platform in the deepwater U.S. Gulf of Mexico, which is operated by Talos Energy. In December 2018, a third well was drilled and logged 130 (true vertical thickness) net feet of pay in the same Pliocene sand. Planned production from the third development well is scheduled for the second quarter of 2019. The two currently producing wells achieved peak production of approximately 30,000 Boepd (gross), and net production from the acquisition date through the end of 2018 averaged approximately 6,000 Boepd.

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Marmalard

The Marmalard field produces from four wells, each completed in Middle Miocene sands. These wells are flowing through the Delta House FPS, operated by LLOG. The four wells achieved peak production of approximately 41,000 Boepd (gross), and net production from the acquisition date through the end of 2018 averaged approximately 3,000 Boepd.

Kodiak

The Kodiak field is producing from one well which is completed in the Middle Miocene sands. This well is flowing through the Devils Tower Spar platform, which is operated by ENI. A second development well is scheduled for drilling in the fourth quarter of 2020. The initial well achieved peak production of approximately 23,000 Boepd (gross), and net production from the acquisition date through the end of 2018 averaged approximately 4,000 Boepd.

South Santa Cruz / Barataria

The South Santa Cruz field is producing from one well in a Late Miocene sand through the Blind Faith tension-leg platform ("TLP"), which is operated by Chevron. The Barataria field is producing from one well in a different Late Miocene sand through the Blind Faith TLP, via South Santa Cruz. A third target in the field is a deeper Late Miocene sand and is expected to be tested during the second quarter of 2020. The two wells achieved peak production of approximately 15,000 Boepd (gross), and net production from the acquisition date through the end of 2018 averaged approximately 2,500 Boepd.

Mauritania

The C6, C8, C12, C13 and C18 blocks are located on the western margin of the Mauritania Salt Basin offshore Mauritania and range in water depths from 100 to 3,000 meters. These blocks are located in a proven petroleum system, with our primary targets being Cretaceous sands in structural and stratigraphic traps. 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.

These blocks cover an aggregate area of approximately 6.0 million acres (gross). 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 additional prospects in our blocks. We continue to integrate the results of our drilling program in Mauritania.

Senegal

The Senegal Blocks are located in the Senegal River Cretaceous petroleum system and range in water depth from 300 to 3,100 meters. 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 additional prospects in our blocks.

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

Greater Tortue Ahmeyim Development

The Ahmeyim and Guembeul discoveries (collectively “Greater Tortue Ahmeyim”) are significant, play-opening gas discoveries for the outboard Cretaceous petroleum system and are located approximately 120 kilometers offshore Mauritania and Senegal. The Greater Tortue Ahmeyim development straddles Block C8 offshore Mauritania and Saint

Louis Offshore Profond offshore Senegal.
We have drilled three wells within the Greater Tortue Ahmeyim development, Tortue-1, Guembeul-1 and Ahmeyim-2. 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 approximately 2,700 meters to 2,800 meters, with total depths drilled ranging from approximately 5,100 meters to 5,250 meters.

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The Tortue-1 discovery well, located in Block C8 offshore Mauritania, intersected approximately 117 meters of net hydrocarbon pay. A single gas pool was encountered in the Lower Cenomanian objective, which is comprised of three reservoirs totaling 88 meters in thickness over a gross hydrocarbon interval of 160 meters. A fourth reservoir totaling 19 meters was penetrated within the Upper Cenomanian target over a gross hydrocarbon interval of 150 meters. The exploration well also intersected an additional 10 meters 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 five kilometers south of the Tortue-1 exploration well in Mauritania. The well encountered 101 meters of net gas pay in two excellent quality reservoirs, including 56 meters in the Lower Cenomanian and 45 meters in the underlying Albian, with no water encountered.

The Ahmeyim-2 appraisal well is located in Block C8 offshore Mauritania, approximately five kilometers northwest, and 200 meters down-dip of the basin-opening Tortue-1 discovery. The well confirmed significant thickening of the gross reservoir sequences down-dip. The Ahmeyim-2 well encountered 78 meters of net gas pay in two excellent quality reservoirs, including 46 meters in the Lower Cenomanian and 32 meters in the underlying Albian.

In August 2017, we completed 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 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 was used to further optimize field development and to refine process design parameters critical to the front end engineering and design ("FEED") process.

In December 2018, the partners agreed on a final investment decision for Phase 1 of the Greater Tortue Ahmeyim project. The Greater Tortue Ahmeyim project is designed to produce gas from a deepwater subsea system to a mid-water FPSO and then to a FLNG facility at a nearshore hub located on the Mauritania and Senegal maritime border. The FLNG facility for Phase 1 is designed to produce approximately 2.5 million tons per annum on average. The project will provide LNG for global export, as well as make gas available for domestic use in both Mauritania and Senegal. First gas for the project is expected in the first half of 2022. Following a competitive tender process involving all partners and subject to final documentation, BP Gas Marketing has been selected as the buyer for the LNG offtake for Greater Tortue Ahmeyim Phase 1.

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 60 kilometers north of the Ahmeyim discovery and was drilled to a total depth of 5,150 meters in nearly 2,400 meters of water. Based on analysis of drilling results and logging data, Marsouin-1 encountered at least 70 meters 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 65 kilometers northwest of Dakar, and was our second exploration well offshore Senegal. The Teranga-1 discovery well is located in nearly 1,800 meters of water and was drilled to a total depth of approximately 4,850 meters. The well encountered 31 meters of net gas pay in good quality reservoir in the Lower Cenomanian objective. Well results confirm that a prolific inboard gas fairway extends approximately 200 kilometers south from the Marsouin-1 well in Mauritania through the Greater Tortue Ahmeyim 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 95 kilometers 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 in three pools within the primary Lower Cenomanian objective and encountered 45 meters of net pay. An appraisal well is planned in 2019.

Equatorial Guinea

In October 2017, we entered into petroleum contracts covering Blocks EG-21, S, and W with the Republic of Equatorial Guinea. The petroleum contracts cover approximately 6,000 square kilometers, with a first exploration period expiring in March

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2023. The first exploration period consists of two sub-periods of three and two years, respectively. The first exploration sub-period work program included an approximately 6,000 square kilometer 3D seismic acquisition requirement across the blocks, which was completed in November 2018.

In June 2018, we closed a farm-in agreement with a subsidiary of Ophir Energy plc ("Ophir") for Block EG-24, offshore Equatorial Guinea, whereby we acquired a 40% non-operated participating interest. As part of the agreement, we reimbursed a portion of Ophir's previously incurred exploration costs and will fully carry Ophir's share of the costs of a planned 3D seismic program as well as pay a disproportionate share of the well commitment should we enter the second exploration sub-period. The petroleum contract covers approximately 3,500 square kilometers, with a first exploration period of three years from the effective date (March 2018) which can be extended up to four additional years at our election subject to fulfilling specific work obligations. The first exploration period work program includes a 3,000 square kilometer 3D seismic acquisition requirement, which was completed in November 2018. In January 2019, we entered into an agreement to acquire Ophir's remaining interest in and operatorship of the block, subject to customary governmental approvals, which will result in Kosmos owning an 80% interest in Block EG-24. Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest for all development and production operations.

In November 2018, we completed a 3D seismic survey of approximately 9,500 square kilometers over blocks EG-21, EG-24, S and W offshore Equatorial Guinea, and approximately 200 square kilometers over Block G. The seismic data will be processed with the objective of high grading prospects for drilling in 2019.

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 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 transaction expands our position in the Gulf of Guinea and provides immediate cash flow through existing production with potential to increase existing production through exploration opportunities with potential low cost tie-backs through the existing infrastructure. 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. The transaction was accounted for as an equity method investment. Oil production from the Ceiba Field and Okume Complex averaged approximately 44,000 barrels gross (28,000 barrels net) of oil per day during 2018.

Effective as of January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.375% undivided interest in the Ceiba Field and Okume Complex. As a result, our interest in the Ceiba Field and Okume Complex will be accounted for under the proportionate consolidation method of accounting going forward.

In May 2018, we signed a farm-out agreement with a subsidiary of Trident covering blocks S, W and EG-21 offshore Equatorial Guinea. Under the terms of the agreement, Trident acquired a 40% non-operated participating interest in the blocks and Kosmos remains the operator. In August 2018, we completed the farm-out agreement covering blocks S, W and EG-21 offshore Equatorial Guinea resulting in a $7.7 million gain.

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 analogous 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

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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.

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.

In June 2018, the Anapai-1A exploration well was drilled to a total depth of approximately 4,600 meters and was designed to test lower Cretaceous reservoirs in a structural trap on the flank of the basin. The prospect was fully tested, encountering high quality reservoirs in the targeted zones, but did not find hydrocarbons. The well has been plugged and abandoned.

In July 2018, we entered into the second exploration phase in blocks 42 and 45, which now expires in September 2021. The second phase carried a one well commitment per block that has been met for both blocks with the Anapai-1A and Pontoenoe-1 exploration wells.

In October 2018, the Pontoenoe-1 exploration well was drilled to a total depth of approximately 6,200 meters and was designed to test late Cretaceous reservoirs in a structural trap charged from oil mature Albian and Cenomanian-Turonian source kitchens. The prospect was fully tested but did not discover commercial hydrocarbons. High-quality reservoir was encountered, but the primary exploration objective proved to be water bearing. The well has been plugged and abandoned.

The well results are being integrated into the ongoing evaluation of the remaining prospectivity in our Suriname acreage position.

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 Energia Sao Tome E Principe, Unipessoal, LDA (“Galp”), a wholly-owned subsidiary of Petrogal, S.A., is the operator of Block 6. In March 2018, as part of our alliance with BP, we entered into petroleum contracts covering Blocks 10 and 13 with the Democratic Republic of Sao Tome and Principe. We presently have a 35% participating interest in the blocks and the operator, BP, holds a 50% participating interest. The national petroleum agency, Agencia Nacional Do Petroleo De Sao Tome E Principe ("ANP STP") has a 15% carried interest in the blocks through exploration. These blocks cover an area of approximately 5.9 million acres (gross) in water depths ranging from 2,250 to 3,000 meters 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. Kosmos has established an extensive position in the Rio Muni Basin where there is a proven source and reservoir inboard with the Ceiba and Okume discoveries in Equatorial Guinea, which appears to extend outboard into the deepwater in Sao Tome and Principe, where there are oil seeps on both islands. Kosmos has identified large potential structural and stratigraphic traps on early seismic, which is currently being processed.

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. 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 has been completed. We are compiling an 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 2019 with a view to drilling as early as 2020.

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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

In August 2018, we provided to the Office National Des Hydrocarbures et des Mines ("ONHYM") a notice to abandon the Essaouira Offshore block, located offshore Morocco, at the end of the then current exploration phase (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 450 to 4,500 meters. 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 exploration targets. In May 2018, we completed a 3D seismic survey covering approximately 12,000 square kilometers over blocks CI-526, CI-602, CI-603, CI-707 and CI-708 offshore Cote d'Ivoire.

Namibia

In September 2018, we acquired a 45% non-operated participating interest in PEL 39 offshore Namibia, which later became part of a larger strategic alliance with Shell to jointly explore in Southern West Africa. The block covers an area of approximately 3.1 million acres in water depth ranging from 250 to 3,000 meters. The blocks provide for multiple plays targeting Cretaceous deepwater systems. We believe the area is positioned within the interpreted oil mature window of the Aptian source rock with reservoir sands sourced from the Orange River. In January 2019, we completed a 3D seismic survey covering approximately 6,000 square kilometers. Processing of this data is currently underway. We are compiling an initial inventory of prospects on the license are as will continue to refine and assess the prospectivity and petroleum systems analysis while integrating the new 3D seismic data in our geological evaluation during 2019 with a view to drilling as early as 2020.

Our Reserves

The following table sets forth summary information about our estimated proved reserves as of December 31, 2018. 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, 2018, were associated with our Jubilee and the TEN fields in Ghana and the U.S. Gulf of Mexico 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, 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 were associated with our Jubilee and TEN fields in Ghana.

Summary of Oil and Gas Reserves

	2018 Net Proved Reserves(1)			2017 Net Proved Reserves(1)			2016 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	82	57	91	59	38	65	64	13	66
Proved undeveloped(3)	45	28	50	23	11	24	10	2	11
Total Kosmos	127	85	141	82	49	89	74	15	77
Equity method investment(4)	24	14	27	19	13	21			

Total reserves	151	99	167	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.

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(2) These reserves include 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.

(4) We disclose our share of reserves that are accounted for by the equity method.

Changes for the year ended December 31, 2018, include an addition of 51.1 MMBoe as a result of the acquisition of DGE. Changes at Greater Jubilee include a revision of 9.4 MMBbl related to strong field performance, positive drilling results and increased original oil in place, partially offset by 6.4 MMBbl of net Jubilee production during 2018. Changes at TEN include a positive revision 4.2 MMBbl due to original oil in place adjustments, new drilling and development plan updates, and a negative revision of 3.1 MMBbl due to recovery factor adjustment from dynamic modeling, which in total were offset by 3.7 MMBoe of net production. Changes at Equatorial Guinea include an increase of 11.0 MMBbl, which comprises 0.7 MMBbl of revision due to economic modeling, 3.9 MMBbl of revision due to strong field performance at both Ceiba and Okume Complex, and 6.4 MMBbl of revision due to reservoir management strategies (re-opening shut-in wells, stimulations, surface/subsurface equipment installation), all of which was partially offset by 5.4 MMBbl of net production. During the year ended December 31, 2018, we had an addition of 13.9 MMBoe of proved undeveloped reserves as a result of the DGE acquisition, we converted 2.0 MMBbl of proved undeveloped reserves to proved developed due to the completion of a new well in TEN, and we added 12.9 MMBbl of proved undeveloped reserves in Jubilee as a result of several factors, including positive results from drilling two new wells, increased oil-in-place due to improved static model utilizing new seismic and petrophysics data, and upgrading volumes associated with Mahogany area that is now part of the Greater Jubilee Unit.

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.

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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, 2018. All estimated future net revenues are attributable to projected production from Ghana, the U.S. Gulf of Mexico and our equity method investment in Equatorial Guinea. 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	$5,487	$ 774	$6,261
Present value of estimated future net revenues:			
PV-10(1)	$3,928	$ 705	$4,633
Future income tax expense (levied at a corporate parent and intermediate subsidiary level)	(1,431)	(416)	(1,847)
Discount of future income tax expense (levied at a corporate parent and intermediate subsidiary level) at 10% per annum	413	102	515
Standardized Measure(2)	$2,910	$ 391	$3,301
Benchmark Dated Brent oil price($/Bbl)(3)			$71.54
Benchmark HLS oil price($/Bbl)(3)			$70.20
Benchmark Henry Hub gas price($/MMBtu)(3)			$3.10

(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 2018 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.

(3) This amount represents the unweighted arithmetic average first day of the month prices for the prior 12 months at December 31, 2018 for the respective benchmark. The benchmark price was adjusted for handling fees, transportation fees, quality, and a regional price differential.

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(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, 2018, 2017 and 2016 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, 2018 are based on costs in effect at December 31, 2018 and the 12 month unweighted arithmetic average of the first day of the month price for the year ended December 31, 2018, 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, 2018, 2017 and 2016, was established in 1937. For over 80 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, 2018, 2017 and 2016, 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, 2018, 2017 and 2016 and related future net revenues and PV 10 at December 31, 2018, 2017 and 2016 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, 2018 reserve report was completed on January 13, 2019, and a copy is included as an exhibit to this report.

In connection with the preparation of the December 31, 2018, 2017 and 2016 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, 2018, based upon its evaluation. RSC's primary economic assumptions in estimates included an ability to sell hydrocarbons at their respective adjusted benchmark prices 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.

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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 a 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. Tosin Famurewa. Mr. Famurewa has been practicing consulting petroleum engineering at RSC since 2006. Mr. Famurewa is a Licensed Professional Engineer in the State of Texas (No. 100569) and has over 18 years of practical experience in petroleum engineering. He graduated from University of California at Berkeley in 2000 with Bachelor of Science Degrees in Chemical Engineering and Material Science Engineering, and he received a Master of Science degree in Petroleum Engineering from University of Southern California in 2007. Mr. Famurewa 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.

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Gross and Net Undeveloped and Developed Acreage

The following table sets forth certain information regarding the developed and undeveloped portions of our license and lease areas as of December 31, 2018 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(2)	163	32	34	7	197	39
Cote d'Ivoire	—	—	4,143	1,865	4,143	1,865
Equatorial Guinea(3)	—	—	2,355	942	2,355	942
Mauritania	—	—	9,275	2,172	9,275	2,172
Namibia	—	—	3,039	1,368	3,039	1,368
Sao Tome and Principe	—	—	9,255	4,270	9,255	4,270
Senegal	—	—	2,116	635	2,116	635
Suriname	—	—	2,793	1,142	2,793	1,142
U.S. Gulf of Mexico	127	35	131	70	258	105
Total Kosmos	290	67	33,141	12,471	33,431	12,538
Equity method investment(4)	65	28	—	—	65	28
Total	355	95	33,141	12,471	33,496	12,566

(1) Net acreage based on Kosmos’ participating interests, 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.

(3) In January 2019, we entered into an agreement to acquire Ophir's remaining interest in the block, subject to customary governmental approvals, which will result in Kosmos owning an 80% interest in Block EG-24. After completion of this transaction, our net acreage in Equatorial Guinea will be 1,292 thousand acres.

(4) Represents our 50% interest in KTIPI. Effective as of January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.375% undivided interest in the Ceiba Field and Okume Complex. As a result, our interest in the Ceiba Field and Okume Complex will be accounted for under the proportionate consolidation method of accounting going forward.

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, 2018:

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	Productive Oil Wells		Productive Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Ghana	41	9.00	—	—	41	9.00
U.S. Gulf of Mexico	17	3.02	—	—	17	3.02
Kosmos Total(1)	58	12.02	—	—	58	12.02
Equity Method Investment(2)(3)	96	38.78	—	—	96	38.78
Total	154	50.80	—	—	154	50.80

(1) Of the 58 productive wells, 20 (gross) or 3.53 (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.

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, 2018														
Ghana	—	—	3	0.80	3	0.80	4	0.89	—	—	4	0.89	7	1.69
U.S. Gulf of Mexico(4)	—	—	—	—	—	—	1	0.55	—	—	1	0.55	1	0.55
Senegal	—	—	1	0.60	1	0.60	—	—	—	—	—	—	1	0.60
Suriname	—	—	2	1.20	2	1.20	—	—	—	—	—	—	2	1.20
Total	—	—	6	2.60	6	2.60	5	1.44	—	—	5	1.44	11	4.04
Year Ended December 31, 2017														
Ghana	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Mauritania	—	—	2	0.56	2	0.56	—	—	—	—	—	—	2	0.56
Total	—	—	2	0.56	2	0.56	—	—	—	—	—	—	2	0.56
Year Ended December 31, 2016														
Ghana	—	—	—	—	—	—	7	1.19	—	—	7	1.19	7	1.19
Total	—	—	—	—	—	—	7	1.19	—	—	7	1.19	7	1.19

(1) As of December 31, 2018, seven 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.
(4) Represents contributions from the U.S. Gulf of Mexico after the acquisition date.

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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, 2018.

	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	—	—	1	0.24	—	—	8	1.93
TEN	—	—	2	0.34	—	—	5	0.85
U.S. Gulf of Mexico								
Nearly Headless Nick	—	—	—	—	1	0.22	—	—
Odd Job 214#2	—	—	—	—	—	—	1	0.61
Tornado	—	—	1	0.35	—	—	—	—
Mauritania								
C8	—	—	—	—	3	0.84	—	—
Senegal								
Saint Louis Offshore Profond	—	—	—	—	1	0.30	—	—
Cayar Profond	—	—	—	—	2	0.60	—	—
Total	—	—	4	0.93	7	1.96	14	3.39

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, 2018, 99 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.

Ghana 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 potential sliding scale royalty ("additional oil entitlement") which comes into effect and escalates as the nominal project rate of return increases above a certain threshold. 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.

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Ghana 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 a potential additional oil entitlement which comes into effect and escalates as the nominal project rate of return increases above a certain threshold. 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 DT petroleum contract has a duration of 30 years from its effective date (July 2006). However, in 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.

Ghana 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 Jubilee UUOA, agreed to in 2009 which governs 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 Jubilee UUOA. Although the Jubilee Field is unitized, Kosmos' participating interests in each block outside the boundary of the Jubilee Unit remain the same. Our Jubilee Unit interest is 24.1% subject to redetermination of the participating interests pursuant to the terms of the Jubilee UUOA. Our paying interest on development activities is 26.9%.

Greater Tortue Ahmeyim Unitization

The Greater Tortue/Ahmeyim Field, discovered by the Tortue 1 well in May 2015, in Mauritania block C8 and by the Guembuel-1 well in January 2016, in the Saint-Louis Offshore Profond block in Senegal covers an area within both the C8 and Saint-Louis Offshore Profond Blocks. Mauritania and Senegal agreed that the Greater Tortue Ahmeyim Field would be unitized for optimal resource recovery in the Inter-State Cooperation Agreement (ICA) signed in February 2018. The GTA UUOA was agreed between the contractor groups of the C8 and Saint-Louis Offshore Profond Blocks and approved by the appropriate Ministers in Mauritania and Senegal in February 2019. BP Mauritania and BP Senegal are co-Unit Operator, and will allocate responsibilities for the initial development of the Greater Tortue Ahmeyim Field. The Greater Tortue Ahmeyim Unit holders' interests are subject to redetermination in accordance with the terms of the GTA UUOA. Although the Greater Tortue Ahmeyim Field is unitized, Kosmos' participating interests in each block outside the boundary of the Greater Tortue Ahmeyim Unit remain the same. Our Unit interest is 29%, subject to SMHPM's right to elect to participate for up to 14% in Block C8 and PETROSEN's right to increase its participating interest to 20% in the Saint-Louis Offshore Profond Block and subject to redetermination of the participating interests pursuant to the terms of the GTA UUOA. In February 2019, Mauritania and Senegal each issued an exploitation authorization for the Greater Tortue Ahmeyim Unit area covered by the GTA UUOA.

Mauritania 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

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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 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, SMHPM, currently has a 10% carried participating interest during the exploration period. We are currently in the first exploration period, which extends four years from the effective date (October 28, 2016).

In September 2017, we acquired a 15% non-operated participating interest in Block C18 offshore Mauritania. 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 has been completed.

Senegal Agreements

In June 2018, we entered the final renewal of the exploration period for the Senegal Blocks Contract Areas, which lasts for two and one half years, ending in December 2020. This exploration phase of each contract area requires one exploration well in the final period. 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.

Equatorial Guinea Exploration Agreements

In March 2018, we entered into petroleum contracts covering Blocks EG-21, S, and W with the Republic of Equatorial Guinea. We currently have a 40% interest in the blocks. 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, which can be extended up to two additional years at our election, subject to fulfilling specific work obligations. The first exploration sub-period work program includes an approximately 6,000 square kilometer 3D seismic acquisition requirement across the three blocks.

In June 2018, we acquired a 40% non-operated participating interest in Block EG-24 offshore Equatorial Guinea. 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 contract covers approximately 3,500 square kilometers, with a first exploration sub-period of three years from the effective date (March 2018) which can be extended up to four additional years at our election, subject to fulfilling specific work obligations. The first exploration sub-period work program includes a 3,000 square kilometer 3D seismic acquisition requirement.

In January 2019, we entered into an agreement to acquire Ophir's remaining interest in the block, subject to customary governmental approvals, which will result in Kosmos owning an 80% interest in Block EG-24.

Sao Tome and Principe Exploration Agreements

Kosmos has interests in petroleum contracts for Blocks 5, 6, 10, 11, 12 and 13 in Sao Tome and Principe.

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In Block 11, 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 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.

In Block 10 and Block 13, ANP-STP has a 15% carried interest. The production sharing contracts were awarded in March 2018 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 2022. 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.

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 second period of the exploration phase, which ends in September 2021. There is one additional period consisting of two years, and 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.

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 second period of the exploration phase, which ends in September 2021. There is one additional period consisting of two years and 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.

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Cote d'Ivoire Exploration Agreements

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.

Namibia Exploration Agreements

In September 2018, we acquired a 45% non-operated participating interest in PEL 39 offshore Namibia. Based on the terms of the agreement we will carry Shell's share of the costs of a planned 3D seismic program subject to a cap. The Namibian national oil company, National Petroleum Corporation of Namibia ("NAMCOR"), currently has a 10% carried participating interest during the exploration period. The carry of NAMCOR's 10% participation interest may continue through first commercial production but must be reimbursed through production. The petroleum contract covers approximately 12,300 square kilometers, with an initial exploration period and two renewals periods. The block is currently in the first renewal period, which has been extended and expires in August 2019. A second renewal period of two years is available at our election, subject to fulfilling specific work obligations. The first renewal period work program has been completed.

Sales and Marketing

As provided under the Jubilee 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 TAG GSA and we began exporting TEN associated gas to shore in the fourth quarter of 2018. The TAG GSA provides for an inflation-adjusted sales price of $0.50 per mmbtu.

As provided under the Production Sharing Contract for Block G, we are entitled to lift and sell our share of the Ceiba Field production as are the other Ceiba Field partners. We have entered into an agreement with an oil marketing agent to market our share of the Ceiba Field 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 the U.S. Gulf of Mexico, we sell crude oil to purchasers typically through monthly contracts, with the sale taking place at multiple points offshore, depending on the particular property. Natural gas is sold to purchasers through monthly contracts, with the sale taking place either offshore or at an onshore gas processing plant after the removal of NGLs. We actively market our crude oil and natural gas to purchasers, and sales prices for purchased oil and natural gas volumes are negotiated with purchasers and are based on certain published indices. Since most of the oil and natural gas contracts are month-to-month, there are very few dedications of production to any one purchaser. We sell the NGLs entrained in the natural gas that we produce. The arrangements to sell these products first requires natural gas to be processed at an onshore gas processing plant. Once the liquids are removed and fractionated (broken into the individual hydrocarbon chains for sale), the products are sold by the processing plant. The residue gas left over is sold to natural gas purchasers as natural gas sales (referenced above). The contracts for NGL sales are with the processing plant. The prices received for the NGLs are either tied to indices or are based on what the processing plant can receive from a third party purchaser. The gas processing and subsequent sales of NGLs are subject to contracts with longer terms and dedications of lease production from the Company’s leases offshore.

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 and leases. 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 and leases 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 continued volatility. Dated Brent crude, the benchmark for our international oil sales, ranged from approximately $50 to $86 per barrel during 2018. HLS crude, the benchmark for our U.S. Gulf of Mexico oil sales, which generally trades at a slight discount to Dated Brent, ranged from approximately $63 to $75 during 2018. Excluding the impact of hedges, our realized price for 2018 was $69.00 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.

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 and leases 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;
- 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

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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.

Per common industry practice, under agreements governing the terms of use of the drilling rigs contracted by us or our block or lease partners, the drilling rig contractors typically 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 our blocks and leases, except in certain circumstances, each block or lease 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 FPSOs which we own. We believe 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.

Capping and Containment (Excluding the U.S. Gulf of Mexico)

We entered into an agreement with a third party service provider for it to supply subsea capping and containment equipment on a global basis (excluding the U.S. Gulf of Mexico). 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. Capping and containment for the U.S. Gulf of Mexico is detailed in the U.S. Gulf of Mexico (Operated and Non-operated) section below.

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 ("GSD"). The dispersant stockpile, which is managed by Oil Spill Response Limited ("OSRL") of Southampton, England, 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. Dispersant from the GSD can be used in the U.S. Gulf of Mexico.

Mauritania and Senegal (Non-operated)

Kosmos transferred operatorship of Mauritania and Senegal operations to BP at the beginning of 2018 for the blocks that were previously operated by Kosmos. Oil spill response equipment in both countries was transferred back to the OSRL Central Stockpile in Southampton, England.

Suriname (Operated)

Kosmos drilled two exploration wells in Suriname in 2018. Kosmos maintained its dispersant spraying capabilities in the field during drilling operations and had additional Tier 2 and Tier 3 equipment from OSRL's Americas base in Ft Lauderdale, Florida on standby.

Ghana (Non-operated)

Tullow, our partner and the operator of the Jubilee Unit and the TEN fields, maintains Oil Spill Contingency Plans ("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.

Equatorial Guinea (Operated and Non-operated)

In 2017, Kosmos entered into a joint venture in Equatorial Guinea through the acquisition KTIPI, which includes the Ceiba Field and Okume Complex. Effective January 1, 2019, Trident became operator of the Ceiba Field and Okume

Complex. In addition, Kosmos is operator of four exploration leases in Equatorial Guinea. Current plans call for drilling one exploration well in 2019. Kosmos will bring in additional equipment in country to supplement existing resources as necessary.

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U.S. Gulf of Mexico (Operated and Non-operated)
After the major well control incident and oil release in the U.S. Gulf of Mexico in 2010, the U.S. Department of Interior updated regulations which govern the type, amount and capabilities of response equipment that needs to be available to operators to respond to similar incidents. These regulations also dictate the type and frequency of training that operating personnel need to receive and demonstrate proficiency in. Kosmos also has an Oil Spill Response Plan ("OSRP") which is approved by the Bureau of Safety and Environmental Enforcement ("BSEE"). This OSRP would be activated if needed in the event of an oil spill or containment event in the U.S. Gulf of Mexico. Kosmos joined several cooperatives that were established to meet the requirements of the new regulations. For capping and containment, Kosmos joined the Helix Well Containment Group ("HWCG") consortium whose capabilities include; (i) two dual ram capping stacks rated at 15,000 psi and 10,000 psi respectively, (ii) intervention equipment to cap and contain a well with the mechanical and structural integrity to be shut in at depths up to 10,000 feet, and (iii) the ability to capture and process 130,000 barrels of fluid per day and 220 Mcf of gas per day. Kosmos is also a member of the Clean Gulf Associate ("CGA") Oil Spill Cooperative, which provides oil spill response capabilities to meet regulatory requirements. Equipment and services include a High Volume Open Sea Skimming System ("HOSS"), dedicated oil spill response vessels strategically positioned along the U.S. gulf coast, dispersant and dispersant delivery systems, various types of spill response booms and mobile wildlife rehabilitation equipment. Due to federal regulations, all of the HWCG and CGA equipment is dedicated to U.S. operations and cannot be utilized outside the country.

Employees
As of December 31, 2018, we had approximately 380 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
On December 28, 2018, we changed our jurisdiction of incorporation from Bermuda to the State of Delaware, USA. Kosmos Energy Ltd. discontinued as a Bermuda exempted company pursuant to Section 132G of the Companies Act 1981 of Bermuda and, pursuant to Section 265 of the General Corporation Law of the State of Delaware (the “DGCL”), continued its existence under the DGCL as a corporation organized in the State of Delaware. This transaction is referred to as the “Redomestication”. The business, assets and liabilities of the Company and its subsidiaries on a consolidated basis, as well as its principal locations and fiscal year, were the same immediately after the Redomestication as they were immediately prior to the Redomestication. In addition, the directors and executive officers of the Company immediately after the Redomestication were the same individuals who were directors and executive officers, respectively, of the Company immediately prior to the Redomestication.
The Company did not change its name in connection with the Redomestication. In the Redomestication, each of the outstanding common shares of Kosmos Energy Ltd., an exempted company incorporated pursuant to the laws of Bermuda, were automatically converted by operation of law, on a one-for-one basis, into shares of common stock of Kosmos Energy Ltd., a company incorporated pursuant to the laws of Delaware. Consequently, each holder of a Kosmos Energy Ltd. common share now holds a share of Kosmos Energy Ltd.’s common stock in each case representing the same proportional equity interest in the Company as that shareholder held prior to the Redomestication. The number of shares of the Company’s common stock outstanding immediately after the Redomestication was the same as the number of common shares of Kosmos Energy Ltd. outstanding immediately prior to the Redomestication. In connection with the Redomestication, the Company adopted a new certificate of incorporation, bylaws and form of common stock certificate, copies of which are filed herewith as Exhibits 3.1, 3.2 and 4.1, respectively.
We maintain a registered office in Delaware at Corporation Trust Center, 1209 Orange Street, Wilmington, Delaware 19801. Our executive offices are maintained at 8176 Park Lane, Suite 500, Dallas, Texas 75231, and its telephone number is +1 (214) 445 9600.

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Available Information

Kosmos is listed on the New York Stock Exchange and London Stock Exchange and our common stock is 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 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.

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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 Mauritania and Senegal, an area in which we currently 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 and development at such depths and the relatively recent discovery of commercial quantities of hydrocarbons in the region. Likewise, our deepwater offshore Cote d'Ivoire, Namibia, Sao Tome and Principe 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.

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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 failure 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 and infrastructure locations are scheduled out over time, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling or infrastructure installation or modification.

Our management team has identified and scheduled drilling locations and possible infrastructure locations on our license and lease 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 or lease partners and national and state regulators, seasonal conditions, oil prices, assessment of risks, costs and drilling results. For example, a shutdown of the U.S. federal government could delay the regulatory review and approval process associated with drilling or developmental activities within our license areas in the U.S. Gulf of Mexico. The final determination on whether to drill or develop 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 and production activities with respect to our established wells and drilling locations. Because of these uncertainties, we do not know if the drilling locations we have identified will be drilled or infrastructure installed or modified 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 and development 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:

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- 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, 2018, 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 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 and Greater Tortue Ahmeyim 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 Jubilee UUOA. The parties to the Jubilee 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 Jubilee 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 Jubilee UUOA will not negatively affect our interests in the Jubilee Unit or that such redetermination will be satisfactorily resolved.

The interests in and development of the Greater Tortue Ahmeyim Field are governed by the terms of the GTA UUOA. The parties to the GTA UUOA, the collective interest holders in each of the Mauritania Block C8 and Senegal Saint Louis Offshore Profond blocks, initially agreed that interests in the Greater Tortue Ahmeyim Unit will be shared equally, with each block deemed to contribute 50% of the area of such unit. The respective interests in the Greater Tortue Ahmeyim Unit were therefore initially determined by the respective interests in such contributed block interests. Pursuant to the terms of the GTA UUOA, the percentage of such contributed interests is subject to a process of redetermination once sufficient development work has been completed in the unit. We cannot assure you that any redetermination pursuant to the terms of the GTA UUOA will not negatively affect our interests in the Greater Tortue Ahmeyim Unit or that such redetermination will be satisfactorily resolved.

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We are not, and may not be in the future, the operator on all of our license areas and facilities 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, Ceiba and Okume or certain producing fields in the U.S. Gulf of Mexico and do not hold operatorship in certain 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, 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;
- the available capacity of processing facilities and related pipelines; 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, 2018.

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.

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. 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 retires, 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

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• 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 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, Equatorial Guinea, and U.S. Gulf of Mexico. 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, 2018, the Jubilee partners

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have provided approximately 99 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 final investment decisions on our gas discoveries and constructing the necessary infrastructure to produce, liquefy and transport the gas to the market as well as finding LNG purchasers. Additionally, such plans are contingent upon receipt of required partner and government approvals.

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 been issued permits from the Ghana EPA to flare natural gas produced from the Jubilee and TEN Fields in limited 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

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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:

- fires, blowouts, spills, cratering and explosions;
- mechanical and equipment problems, including unforeseen engineering complications;
- 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.

Our operations may be materially adversely affected by tropical storms and hurricanes.

Tropical storms, hurricanes and the threat of tropical storms and hurricanes often result in the shutdown of operations, particularly in the U.S. Gulf of Mexico, as well as operations within the path and the projected path of the tropical storms or hurricanes. In addition, climate change could result in an increase in the frequency and severity of tropical storms, hurricanes or other extreme weather events. Weather events have caused significant disruption to the operations of offshore and coastal facilities in the U.S. Gulf of Mexico region. In the future, during a shutdown period, we may be unable to access wellsites and our services may be shut down. Additionally, tropical storms or hurricanes may cause evacuation of personnel and damage to our platforms and other equipment, which may result in suspension of our operations. The shutdowns, related evacuations and damage can create unpredictability in activity and utilization rates, as well as delays and cost overruns, which could have a material adverse effect on our business, financial condition 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.

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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 complete remediation of the turret bearing issue on the FPSO. 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 has performed remediation work on the water injection risers and additional work may be required on the gas injection riser depending on the analysis of instrumentation data of the risers to make a final determination if operational fatigue has occurred. Such remediation efforts may negatively impact oil production, and/or result in additional expenses.

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 Jubilee 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 Ghanaian Revenue Authority (the “GRA”), 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 or other payments 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.

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A large portion of 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.

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 GRA previously disputed certain tax deductions we had 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 and other payments.

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 Kingdom 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.

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More comprehensive and stringent regulation in the U.S. Gulf of Mexico has significantly increased costs and delays in offshore oil and natural gas exploration and production operations.

In the U.S. Gulf of Mexico, there have been a series of regulatory initiatives developed and implemented at the federal level to address the direct impact of the incident and to prevent similar incidents in the future. Beginning in 2010 and continuing through the present, the Department of Interior ("DOI") through the Bureau of Ocean Energy Management ("BOEM") and the Bureau of Safety and Environmental Enforcement ("BSEE"), has issued a variety of regulations and Notices to Lessees and Operators ("NTLs"), intended to impose additional safety, permitting and certification requirements applicable to exploration, development and production activities in the U.S. Gulf of Mexico. These regulatory initiatives effectively slowed down the pace of drilling and production operations in the U.S. Gulf of Mexico as adjustments were being made in operating procedures, certification requirements and lead times for inspections, drilling applications and permits, and exploration and production plan reviews, and as the federal agencies evolved into their present day bureaus. On April 17, 2015, BSEE published a proposed rule that would impose more stringent standards on blowout preventers ("BOP"). In April 2016, BSEE issued a final version of this rule effective July 2016, though some requirements of the rule have delayed compliance deadlines. The final rule addresses the full range of systems and equipment associated with well control operations, focusing on requirements for BOPs, well design, well control casing, cementing, real-time monitoring and subsea containment. Key features of the well control regulations include requirements for BOPs, double shear rams, third-party reviews of equipment, real time monitoring data, safe drilling margins, centralizers, inspections and other reforms related to well design and control, casing, cementing and subsea containment. On March 28, 2017, President Trump signed an executive order (the "March 2017 Executive Order") directing federal agencies to initiate rulemakings to suspend, revise or rescind certain regulations relating to the energy industry as necessary to ensure consistency with the goals of energy independence, economic growth and cost-effective environmental regulation. In response to the March 2017 Executive Order and a subsequent executive order issued by President Trump in April 2017 focusing on offshore energy development, in May 2018, BSEE published a proposal to relax certain requirements of the July 2016 rule. The proposed rule's comment period expired on August 6, 2018, but a final rule has not yet been published; this rule is likely to be subject to legal challenges.

In addition to the array of new or revised safety, permitting and certification requirements developed and implemented by the DOI in the past few years, there have been a variety of proposals to change existing laws and regulations that could affect offshore development and production, such as, for example, a proposal to significantly increase the minimum financial responsibility demonstration required under the Oil Pollution Act of 1990. To the extent the existing regulatory initiatives implemented and pursued over the past few years or any future restrictions, whether through legislative or regulatory means or increased or broadened permitting and enforcement programs, foster uncertainties or delays in our offshore oil and natural gas development or exploration activities, then such conditions may have a material adverse effect on our business, financial condition and results of operations.

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.

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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 Jubilee 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.

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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, 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, 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;

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

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.

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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 stock. 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.
Market volatility and reduced consumer demand may increase economic uncertainty. 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 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:

- production is less than the volume covered by the derivative instruments;

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- 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 stock of an opportunity to sell their common stock at a premium over prevailing market prices.

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

At December 31, 2018, we had $1,325.0 million outstanding and $375.0 million of committed undrawn capacity, which includes the $200 million in additional commitments secured in the fourth quarter of 2018, under our commercial debt facility, subject to borrowing base availability. As of December 31, 2018, we had $325 million outstanding under the Corporate Revolver and the undrawn availability was $75.0 million. As of December 31, 2018, there were seven outstanding letters of credit totaling $14.4 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 Equatorial Guinea 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

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do not receive 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 acquisition of DGE) 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.

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

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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.

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.

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.

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.

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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 Stock

Our share price may be volatile, and purchasers of our common stock 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 stock 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 the United States and foreign countries where we operate;

- the recruitment or departure of key personnel;

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- 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 stock or changes in financial estimates by analysts;
- the inability to meet the financial estimates of analysts who follow our common stock;
- 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 stock may be sold into the market at any time. This could cause the market price of our common stock 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 shares of common stock 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 shares of common stock 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 shares of our common stock, or the perception in the market that the holders of a large number of shares intend to sell common stock, could reduce the market price of our common stock.

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

We may issue additional shares of common stock, 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 shares of common stock 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 shares of common stock in the future, it may have a dilutive effect on our current outstanding shareholders.

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 "Item 8. Financial Statements and Supplementary Data—Note 15—Commitments and Contingencies" 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 ("ICC") against Tullow Ghana Limited in connection with a dispute arising under the DT Joint Operating Agreement. At dispute

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was 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 sought to charge such expenditures to the Deepwater Tano ("DT") joint account. Kosmos disputed that these expenditures were 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 and that the Seadrill West Leo drilling rig contract had not been entered into in connection with joint operations.

In July 2018, the ICC issued its Final Award in the arbitration in favor of Kosmos. As a result, we recovered from Tullow Ghana Limited disputed charges in the amount of $12.9 million in the form of cash payments and offsets against other unrelated joint venture costs, which include amounts previously paid under protest as well as certain costs and fees incurred pursuing the arbitration. Additionally, we were not required to fund a portion, estimated by Tullow to be approximately $50.8 million, of Tullow's liability to Seadrill.

Item 4. Mine Safety Disclosures

Not applicable.

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PART II

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

Common Stock Trading Summary

Our common stock is traded on the NYSE and LSE under the symbol KOS.

As of February 20, 2019, based on information from the Company's transfer agent, Computershare Trust Company, N.A., the number of holders of record of Kosmos' common stock was 64. On February 20, 2019, the last reported sale price of Kosmos' common stock, as reported on the NYSE, was $5.82 per share.

We anticipate we may begin to pay dividends on our common stock beginning in fiscal year 2019 following our redomestication to Delaware. Certain of our subsidiaries are 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.

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 stock 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. In addition, in November 2018, Kosmos repurchased 35 million shares of our common stock from funds affiliated with Warburg Pincus LLC in a privately negotiated transaction at a price per share of $5.38. The following table outlines the total number of shares purchased during fiscal year 2018 and the average price paid per share.

	Total Number of Shares Purchased (In thousands)	Average Price Paid per Share
January 1, 2018—January 31, 2018	74	$ 6.85
February 1, 2018—February 28, 2018	—	—
March 1, 2018—March 31, 2018	—	—
April 1, 2018—April 30, 2018	—	—
May 1, 2018—May 31, 2018	—	—
June 1, 2018—June 30, 2018	—	—
July 1, 2018—July 31, 2018	—	—
August 1, 2018—August 31, 2018	—	—
September 1, 2018—September 30, 2018	—	—
October 1, 2018—October 31, 2018	—	—
November 1, 2018—November 30, 2018	35,000	5.38
December 1, 2018—December 31, 2018	—	—
Total	35,074	5.38

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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, 2018, in cumulative total stockholder return on our common stock 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 stock and in each index (with the reinvestment of all dividends).

	December 31,					
	2013	2014	2015	2016	2017	2018
Kosmos Energy Ltd. (KOS)	$100.00	$75.05	$46.51	$62.70	$61.27	$36.40
S&P 500 (SPX)	100.00	113.68	115.24	129.02	157.17	150.27
Dow Jones U.S. Exploration & Production Index (DWCEXP)	100.00	87.53	66.34	83.40	83.63	67.49

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Item 6. Selected Financial Data

The following selected consolidated financial information set forth below as of and for the five years ended, December 31, 2018, 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,				
	2018	2017	2016	2015	2014
	(In thousands, except per share data)				
Revenues and other income:					
Oil and gas revenue	$886,666	$578,139	$310,377	$446,696	$855,877
Gain on sale of assets	7,666	—	—	24,651	23,769
Other income, net	8,037	58,697	74,978	209	3,092
Total revenues and other income	902,369	636,836	385,355	471,556	882,738
Costs and expenses:					
Oil and gas production	224,727	126,850	119,367	105,336	100,122
Facilities insurance modifications, net	6,955	(820)	14,961	—	—
Exploration expenses	301,492	216,050	202,280	156,203	93,519
General and administrative	99,856	68,302	87,623	136,809	135,231
Depletion and depreciation	329,835	255,203	140,404	155,966	198,080
Interest and other financing costs, net	101,176	77,595	44,147	37,209	45,548
Derivatives, net	(31,430)	59,968	48,021	(210,649)	(281,853)
Restructuring charges	—	—	—	—	11,742
(Gain)loss on equity method investment	(72,881)	6,252	—	—	—
Other expenses, net	(6,501)	5,291	23,116	5,246	2,081
Total costs and expenses	953,229	814,691	679,919	386,120	304,470
Income (loss) before income taxes	(50,860)	(177,855)	(294,564)	85,436	578,268
Income tax expense (benefit)	43,131	44,937	(10,784)	155,272	298,898
Net income (loss)	$(93,991)	$(222,792)	$(283,780)	$(69,836)	$279,370
Net income (loss) per share:					
Basic	$(0.23)	$(0.57)	$(0.74)	$(0.18)	$0.73
Diluted	$(0.23)	$(0.57)	$(0.74)	$(0.18)	$0.72
Weighted average number of shares used to compute net income (loss) per share:					
Basic	404,585	388,375	385,402	382,610	379,195
Diluted	404,585	388,375	385,402	382,610	386,119

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Consolidated Balance Sheets Information:

	December 31,				
	2018	2017	2016	2015(1)(2)	2014(1)
	(In thousands)				
Cash and cash equivalents	$173,515	$233,412	$194,057	$275,004	$554,831
Total current assets	509,700	533,602	475,187	734,148	1,010,476
Total property and equipment, net	3,459,701	2,317,828	2,708,892	2,322,839	1,784,846
Total other assets	118,788	341,173	157,386	146,063	131,537
Total assets	4,088,189	3,192,603	3,341,465	3,203,050	2,926,859
Total current liabilities	384,308	428,730	370,025	456,741	448,771
Total long-term liabilities	2,762,403	1,866,761	1,890,241	1,420,796	1,139,129
Total shareholders' equity	941,478	897,112	1,081,199	1,325,513	1,338,959
Total liabilities and shareholders' equity	4,088,189	3,192,603	3,341,465	3,203,050	2,926,859

(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,				
	2018	2017	2016(1)	2015(1)	2014(1)
	(In thousands)				
Net cash provided by (used in):					
Operating activities	$260,491	$236,617	$52,077	$440,779	$443,586
Investing activities	(985,138)	(152,565)	(537,763)	(796,433)	(368,603)
Financing activities	605,277	(52,261)	448,019	79,634	(139,184)

(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.

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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 full-cycle deepwater independent oil and gas exploration and production company focused along the Atlantic Margins. Our key assets include production offshore Ghana, Equatorial Guinea and U.S. Gulf of Mexico, as well as a world-class gas development offshore Mauritania and Senegal. We also maintain a sustainable exploration program balanced between proven basin infrastructure-led exploration (Equatorial Guinea and U.S. Gulf of Mexico), emerging basins (Mauritania, Senegal and Suriname) and frontier basins (Cote d'Ivoire, Namibia and Sao Tome and Principe).

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Recent Developments
Shell Alliance

In October 2018, Kosmos entered into a strategic exploration alliance with Shell Exploration Company B.V. (“Shell”) to jointly explore in Southern West Africa. Initially the alliance will focus on Namibia where Kosmos has completed a farm-in to Shell's acreage in PEL 39, and Sao Tome & Principe where we have entered into exclusive negotiations for Shell to take an interest in Kosmos’ acreage in Blocks 5, 6, 11, and 12. As part of the alliance, the two companies will also jointly evaluate opportunities in adjacent geographies. This alliance is consistent with Kosmos’ strategy of partnering with supermajors to leverage complementary skill sets. Shell has deep expertise in carbonate plays, while Kosmos brings significant knowledge of the Cretaceous in West Africa. Furthermore, by working with Shell, Kosmos has a partner with the expertise to move exploration successes efficiently through the development stage.

Corporate

In February 2018, the Company amended and restated our commercial debt facility (the "Facility") with a total commitment of $1.7 billion after the election to exercise $0.2 billion of additional commitments in December 2018, with additional commitments up to $0.3 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 recorded a $4.1 million loss on the extinguishment of debt in the first quarter of 2018.

In August 2018, we amended and restated the Corporate Revolver from a number of financial institutions, maintaining the borrowing capacity at $400.0 million, extending the maturity date from November 2018 to May 2022 and lowering the margin 100 basis points to 5%. This also results in lower commitment fees on the undrawn portion of the total commitments, which is 30% per annum of the respective margin. The Corporate Revolver is available for general corporate purposes and for oil and gas exploration, appraisal and development programs.

See “—Liquidity and Capital Resources” for additional information regarding the Facility and the Corporate Revolver.

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. In February 2018, the LC Facility was increased to $73.0 million to facilitate the issuance of additional letters of credit. In July 2018 and December 2018, the LC Facility size was voluntarily reduced to $40.0 million and $20.0 million, respectively, based on the expiration of several large outstanding letters of credit.
In November 2018, Kosmos repurchased 35 million shares of our common stock from funds affiliated with Warburg Pincus LLC in a privately negotiated transaction at a price per share of $5.38 per share. The total aggregate purchase price for the share repurchase was approximately $188.0 million.

In December 2018, Kosmos changed its jurisdiction of incorporation from Bermuda to the State of Delaware (the "Redomestication"). Kosmos Energy Ltd. discontinued as a Bermuda exempted company pursuant to Section 132G of the Companies Act 1981 of Bermuda and, pursuant to Section 265 of the DGCL, continued its existence under the DGCL as a corporation organized in the State of Delaware. The Company did not change its name in connection with the Redomestication and the Company’s common stock will continue to trade on the NYSE and the LSE under the symbol “KOS”. See “Item 1. Business-Corporate Information” for additional detail.

Following our Redomestication, Kosmos Energy Ltd., will file a consolidated U.S income tax return with its wholly-owned U.S. subsidiaries, subject to a 21% U.S. statutory tax rate. Prior to the Redomestication Kosmos Energy Ltd.'s pre-tax losses were subject to a 0% Bermuda statutory tax rate.

Ghana

Jubilee

During the year ended December 31, 2018, Jubilee production averaged approximately 78,000 bopd as two new producer wells were brought online during 2018. Production from these wells, together with enhancements to gas handling capacity, is expected to increase production towards the FPSO nameplate capacity of 120,000 bopd. The Jubilee turret remediation work is progressing as planned. Kosmos and its partners completed the lifting and locking of the main turret bearing, and the rotation of the vessel to its final heading in the second half of 2018. Permanent spread mooring of the vessel is expected to be completed around mid-year 2019.

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The financial impact of lower Jubilee production due to the turret bearing issue, 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.

Tweneboa, Enyenra and Ntomme ("TEN")

During the year ended December 31, 2018, TEN production averaged approximately 64,500 bopd as one new producer well at Ntomme came online. Kosmos expects a second new production well, due to be brought online in in the first quarter of 2019, to increase production towards the FPSO nameplate capacity. The TEN FPSO has previously been tested at rates above the 80,000 bopd nameplate capacity, and Kosmos expects to further test this capacity in 2019 as additional wells come online.

Other

A second rig, which arrived in Ghana in September 2018, is being used for drilling operations, with the first rig set up for a continuous completion program. Taking advantage of low rig rates in the current environment is expected to accelerate the addition of new wells in Ghana, increasing Jubilee and TEN production towards their FPSO capacities.

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 was 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 sought to charge such expenditures to the DT joint account. Kosmos disputed that these expenditures were 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 and that the Seadrill West Leo drilling rig contract had not been entered into in connection with joint operations.

In July 2018, the International Chamber of Commerce ("ICC") issued its Final Award in the arbitration in favor of Kosmos. As a result, we recovered from Tullow Ghana Limited the disputed charges in the amount of $12.9 million in the form of cash payments and offsets against other unrelated joint venture costs, which include amounts previously paid under protest as well as certain costs and fees incurred pursuing the arbitration. Additionally, we were not required to fund a portion, estimated by Tullow to be approximately $50.8 million, of Tullow's liability to Seadrill.

U.S. Gulf of Mexico

In September 2018, we completed the acquisition of Deep Gulf Energy (together with its subsidiaries "DGE"), a deepwater company operating in the U.S. Gulf of Mexico, from First Reserve Corporation and other shareholders for a total consideration of $1.275 billion, comprised of $952.6 million in cash, $307.9 million in Kosmos common stock and $14.9 million of transaction related costs. We funded the cash portion of the purchase price using cash on hand and drawings under our existing credit facilities.

As part of the DGE transaction, Kosmos acquired a portfolio of producing assets, infrastructure-led exploration growth assets, and a high-quality inventory of exploration prospects. During the third quarter, the Nearly Headless Nick prospect (22.0% working interest) was successfully drilled to a total depth of 19,052 feet and encountered approximately 85 feet of net pay in the Middle Miocene objective within the Mississippi Canyon 387 block. Nearly Headless Nick, a subsea tie back, which is expected to be brought online through the Delta House facility in the fourth quarter 2019, adds near-term reserves and production growth.

During the third quarter of 2018, Kosmos expanded its inventory as one of the most active participants in U.S. Gulf of Mexico Lease Sale 251 in which we were awarded seven new deepwater blocks. As part of the Company's strategy to expand its position in the U.S. Gulf of Mexico, Kosmos incurred approximately $50.0 million of exploration expense to acquire seismic over new prospective areas and to re-license seismic over existing fields during the third quarter.

In late September, a second development well was brought online at Odd Job in Mississippi Canyon Block 215 (54.9% WI) and connected to the Delta House facility, providing near-term growth at the field. A third Odd Job well located in Mississippi Canyon Block 214 (61.1% working interest) drilled in May 2018 is expected to start production through existing subsea infrastructure to the Delta House facility in the fourth quarter 2019.

During the fourth quarter of 2018, the Tornado #3 development well (35.0% working interest) was successfully drilled to a total depth of 21,600 feet and encountered approximately 130 feet of net pay in the Pliocene objective within the Green Canyon

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Block 281. Tornado #3, a subsea tie back, is expected to be brought online through the Helix Producer I, the vessel to which Tornado production flows, in the second quarter of 2019.

Our U.S. Gulf of Mexico production during the period from transaction close until the end of the 2018 averaged approximately 23,700 boepd (net) (~81% oil).

During the first quarter of 2019, Kosmos expanded its relationship with BP to grow Kosmos' footprint in the deepwater U.S. Gulf of Mexico. The venture includes the evaluation of 18 jointly owned leases in the Garden Banks area and an opportunity to earn an interest in three additional blocks in other areas of the deepwater U.S. Gulf of Mexico. This agreement will allow both companies to leverage complementary skill sets to execute farm-in projects around existing infrastructure. Kosmos will be designated operator and plans to commence drilling operations on the first well in 2019.

During the first quarter of 2019, Kosmos executed a farm-in agreement with Chevron covering the right to earn an interest in a strategic block in the deepwater U.S. Gulf of Mexico. This agreement allows Kosmos another opportunity to execute its deepwater U.S. Gulf of Mexico strategy of lower risk prospects with the potential for subsea development near existing midstream infrastructure. Kosmos will be designated operator and plans to commence drilling operations in 2019.

Pre-tax income from our U.S. Gulf of Mexico operations are taxable at a 21% U.S. statutory tax rate. Our 2018 financial results reflect U.S. Gulf of Mexico operations from September 14, 2018 to December 31, 2018. Our financial results for 2019 will reflect a full-year of U.S. Gulf of Mexico operations, which will impact our overall effective tax rate.

Equatorial Guinea

In June 2018, we completed a farm-in agreement with a subsidiary of Ophir Energy plc ("Ophir") for Block EG-24, offshore Equatorial Guinea, whereby we acquired a 40% non-operated participating interest. As part of the agreement, we reimbursed a portion of Ophir's previously incurred exploration costs and will fully carry Ophir's share of the costs of a planned 3D seismic program as well as pay a disproportionate share of the well commitment should we enter the second exploration sub-period. The petroleum contract covers approximately 3,500 square kilometers, with a first exploration period of three years from the effective date (March 2018) which can be extended up to four additional years at our election subject to fulfilling specific work obligations. The first exploration period work program includes a 3,000 square kilometer 3D seismic acquisition requirement which was completed in November 2018. In January 2019, entered into an agreement to acquire Ophir's remaining interest in and operatorship of the block, subject to customary governmental approvals, which will result in Kosmos owning an 80% interest in Block EG-24. GEPetrol has a 20% carried interest and should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest for all development and production operations.

In August 2018, we completed a farm-out agreement with a subsidiary of Trident Energy ("Trident"), covering blocks S, W and EG-21 offshore Equatorial Guinea resulting in a $7.7 million gain. Under the terms of the agreement, Trident acquired a 40% non-operated participating interest in the blocks and Kosmos remains the operator.

In November 2018, we completed a 3D seismic survey of approximately 9,500 square kilometers over blocks EG-21, EG-24, S and W offshore Equatorial Guinea, and approximately 200 square kilometers over Block G. The seismic will be processed with the objective of high grading prospects for drilling as early as 2019.

Production in Equatorial Guinea averaged approximately 44,100 bopd (gross) for the year ended December 31, 2018. Through December 2018, Kosmos has received approximately $258 million in dividends from the Kosmos-Trident joint venture (over 100 percent of the $231 million purchase price), which equates to a payback of less than one year.

Effective January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.375% undivided interest in the Ceiba Field and Okume Complex. As a result, our interest in the Ceiba Field and Okume Complex will be accounted for under the proportionate consolidation method of accounting going forward. Pre-tax income from our interests in our Ceiba Field and Okume Complex are taxable in Equatorial Guinea at a 35% statutory tax rate, which will impact our overall effective tax rate.

Greater Tortue Ahmeyim

In February 2018, the governments of Mauritania and Senegal signed an Inter-Governmental Cooperation Agreement ("ICA"), which enabled the development of the cross-border Tortue natural gas field to continue moving forward. With this agreement in place, all major FEED contracts have been awarded by the operator.

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In December 2018, Kosmos and its partners announced that a final investment decision for Phase 1 of the Greater Tortue Ahmeyim project has been agreed. The Greater Tortue Ahmeyim project will produce gas from a deepwater subsea system to a mid-water FPSO then to a FLNG facility at a nearshore hub located on the Mauritania and Senegal maritime border. The FLNG facility for Phase 1 is expected to deliver approximately 2.5 million tons per annum on average. The project will provide LNG for global export, as well as make gas available for domestic use in both Mauritania and Senegal. First gas for the project is expected in the first half of 2022. Following a competitive tender process and subject to final documentation, BP Gas Marketing has been selected as the buyer for the LNG offtake for all parties of Greater Tortue Ahmeyim Phase 1.

In February 2019, Mauritania and Senegal each issued an exploitation authorization for the Greater Tortue Ahmeyim Unit area covered by the GTA UUOA. Kosmos and BP signed Carry Advance Agreements with the national oil companies of Mauritania and Senegal, which obligate us separately to finance the respective national oil company's share of certain development costs. Kosmos' total share for the two agreements combined is up to $239.7 million, which is to be repaid through the national oil companies' share of future revenues.

Mauritania

In June 2018, we completed a 9,400 square kilometer survey over Block C18 offshore Mauritania.

Senegal

In February 2018, the Requin Tigre-1 exploration well was drilled to a total depth of 5,200 meters and 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.

In July 2018, we entered into the second renewal of the exploration period for the Senegal Blocks contract areas, which lasts for two and one half years. Each of the contract areas requires one exploration well to be drilled during the second renewal period. 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.

Suriname

In June 2018, the Anapai-1A exploration well was drilled to a total depth of approximately 4,600 meters and was designed to test lower Cretaceous reservoirs in a structural trap on the flank of the basin. The prospect was fully tested, encountering high quality reservoirs in the targeted zones, but did not find hydrocarbons. The well has been plugged and abandoned and the well results integrated into the ongoing evaluation of the remaining prospectivity in our Suriname acreage position.

In July 2018, we entered into the second exploration phase in blocks 42 and 45. The second phase carries a one well commitment per block. This commitment has been met for both blocks.

In October 2018, the Pontoenoe-1 exploration well was drilled to a total depth of approximately 6,200 meters and was designed to test late Cretaceous reservoirs in a structural trap charged from oil mature Albian and Cenomanian-Turonian source kitchens. The prospect was fully tested but did not discover commercial hydrocarbons. High-quality reservoir was encountered, but the primary exploration objective proved to be water bearing. The well has been plugged and abandoned and the well results integrated into the ongoing evaluation of the remaining prospectivity in our Suriname acreage position.

Sao Tome and Principe

In March 2018, as part of our alliance with BP, we entered into petroleum contracts covering Blocks 10 and 13 with the Democratic Republic of Sao Tome and Principe. We presently have a 35% participating interest in the blocks and the operator, BP, holds a 50% participating interest. The national petroleum agency, Agencia Nacional Do Petroleo De Sao Tome E Principe ("ANP-STP") has a 15% carried interest in the blocks through exploration. The petroleum contracts cover approximately 13,600 square kilometers, with a first exploration period of four years from the effective date (March 2018). The exploration periods can be extended an additional four years at our election subject to fulfilling specific work obligations. The first exploration period work programs include a 13,500 square kilometer 3D seismic acquisition requirement across the two blocks.

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Cote d'Ivoire

In May 2018, we completed a 3D seismic survey covering approximately 12,000 square kilometers over blocks CI-526, CI-602, CI-603, CI-707 and CI-708 offshore Cote d'Ivoire.

Namibia

In September 2018, we acquired a 45% non-operated participating interest in PEL 39 offshore Namibia. The block covers an area of approximately 3.1 million acres in water depth ranging from 250 to 3,000 meters. The blocks provide for multiple plays targeting Cretaceous deepwater systems. We believe the area is positioned within the interpreted oil mature window of the Aptian shale source rock with sands sourced from the Orange River. In January 2019, we completed a 3D seismic survey covering approximately 6,000 square kilometers. Processing of this data is currently underway. We are compiling an initial inventory of prospects on the license while integrating the new 3D seismic data in our geological evaluation during 2019 with a view to drilling as early as 2020.

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Results of Operations

All of our results, as presented in the table below, represent operations from the Jubilee and TEN fields in Ghana, the U.S. Gulf of Mexico (commencing September 14, 2018, the DGE acquisition date), and our equity method investment offshore Equatorial Guinea. Certain operating results and statistics for the years ended December 31, 2018, 2017 and 2016 are included in the following tables:

	Year Ended December 31, 2018		
	Kosmos	Equity Method Investment-Equatorial Guinea(1)	Total
	(In thousands, except per volume data)		
Sales volumes:			
Oil (MBbl)	12,673	5,228	17,901
Gas (MMcf)	2,268	—	2,268
NGL (MBbl)	179	—	179
Total (MBoe)	13,230	5,228	18,458
Revenues:			
Oil sales	$874,382	$ 360,649	$1,235,031
Average oil sales price per Bbl	69.00	68.98	68.99
Gas sales	7,101	—	7,101
Average gas sales price per Mcf	3.13	—	3.13
NGL sales	5,183	—	5,183
Average NGL sales price per Bbl	29.00	—	28.96
Costs:			
Oil and gas production, excluding workovers	$217,818	$ 73,843	$291,661
Oil and gas production, workovers	6,909	—	6,909
Total oil and gas production costs	$224,727	$ 73,843	$298,570
Depletion and depreciation	$329,835	$ 134,983	$464,818
Average cost per Boe:			
Oil and gas production, excluding workovers	$16.46	$ 14.12	$15.80
Oil and gas production, workovers	0.52	—	0.38
Total oil and gas production costs	16.98	14.12	16.18
Depletion and depreciation	24.93	25.82	25.18
Oil and gas production cost and depletion and depreciation costs	$41.91	$ 39.94	$41.36

(1) For the year ended December 31, 2018, we have presented our 50% share of the results of operations, including our basis difference which is reflected in depletion and depreciation. Under the equity method of accounting, we only recognize our share of the net income of KTIPI as adjusted for our basis differential, which is recorded in (Gain) loss on equity method investments, net in the consolidated statement of operations.

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

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(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, including our basis difference which is reflected in depletion and depreciation. Under the equity method of accounting, we only recognize our share of the net income of KTIPI as adjusted for our basis differential, which is recorded in (Gain) loss on equity method investments, net in the consolidated statement of operations.

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	Year Ended December 31, 2016 (In thousands, except per volume data)
Sales volumes:	
Oil (MBbl)	6,756
Gas (MMcf)	—
NGL (MBbl)	—
Total (MBoe)	6,756
Revenues:	
Oil sales	$ 310,377
Average oil sales price per Bbl	45.94
Costs:	
Oil and gas production, excluding workovers	$ 119,758
Oil and gas production, workovers	(391)
Total oil and gas production costs	$ 119,367
Depletion and depreciation	$ 140,404
Average cost per Boe:	
Oil and gas production, excluding workovers	$ 17.73
Oil and gas production, workovers	(0.06)
Total oil and gas production costs	17.67
Depletion and depreciation	20.78
Oil and gas production cost and depletion and depreciation costs	$ 38.45

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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, 2018 vs. 2017

	Years Ended December 31, 2018	2017	Increase (Decrease)
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	$886,666	$578,139	$308,527
Gain on sale of assets	7,666	—	7,666
Other income, net	8,037	58,697	(50,660)
Total revenues and other income	902,369	636,836	265,533
Costs and expenses:			
Oil and gas production	224,727	126,850	97,877
Facilities insurance modifications, net	6,955	(820)	7,775
Exploration expenses	301,492	216,050	85,442
General and administrative	99,856	68,302	31,554
Depletion and depreciation	329,835	255,203	74,632
Interest and other financing costs, net	101,176	77,595	23,581
Derivatives, net	(31,430)	59,968	(91,398)
(Gain) loss on equity method investments, net	(72,881)	6,252	(79,133)
Other expenses, net	(6,501)	5,291	(11,792)
Total costs and expenses	953,229	814,691	138,538
Loss before income taxes	(50,860)	(177,855)	126,995
Income tax expense	43,131	44,937	(1,806)
Net loss	$(93,991)	$(222,792)	$128,801

The results of operations for our equity method investments are presented in "(Gain) 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 $308.5 million primarily as a result of higher oil prices during the year ended December 31, 2018, compared to the year ended December 31, 2017. We sold 12,673 MBbl at an average realized price per barrel of $69.00 in 2018 and 10,761 MBbl at an average realized price per barrel of $53.73 in 2017. The increase in barrels sold is primarily a result of the DGE acquisition which was completed in September 2018.

Gain on sale of assets. In August 2018, we closed a farm-out agreement with Trident. As part of the transaction, we received proceeds in excess of our book basis resulting in a gain of $7.7 million.

Other income. Other income, net decreased by $50.7 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. The LOPI claim was finalized in June 2017.

Oil and gas production. Oil and gas production costs increased by $97.9 million during the year ended December 31, 2018 as compared to the year ended December 31, 2017 primarily as a result of the impact of LOPI claim insurance proceeds recognized in 2017 related to increased costs due to turret issues, which reduced overall operating costs as well as credit accrual adjustments from the operator of the Jubilee and TEN fields recognized during the year ended December 31, 2017. The LOPI claim was finalized in June 2017 and therefore no proceeds were received in 2018. Additionally, we recognized $31.0 million of oil and gas production costs during 2018 related to the U.S. Gulf of Mexico as a result of the DGE acquisition.

Facilities insurance modifications, net. During the year ended December 31, 2018, we incurred $50.2 million of facilities insurance modification costs associated with the long-term solution to the Jubilee turret bearing issue. These costs were offset by

$43.2 million of hull and machinery insurance proceeds received during the year ended December 31, 2018, resulting in a net charge of $7.0 million. The difference between the amount of costs incurred and the insurance proceeds recovered are primarily related to timing. During the year ended December 31, 2017, we incurred $19.7 million of facilities insurance modifications costs associated with the long-term solution to the Jubilee turret bearing issue, which was offset by $20.5 million of hull and machinery insurance proceeds received during the year ended December 31, 2017, resulting in a net credit of $0.8 million.
Exploration expenses. Exploration expenses increased by $85.4 million during the year ended December 31, 2018, as compared to the year ended December 31, 2017. The change is primarily a result of $57.1 million of unsuccessful well costs related to Suriname drilling and $57.7 million of unsuccessful well costs for the Wawa-1 and Akasa-1 exploration wells in Ghana, which were previously capitalized as suspended well costs and approximately $60.0 million related to seismic acquisition costs in the U.S. Gulf of Mexico incurred in 2018. These increases were offset by $90.2 million of rig related costs incurred in 2017 but not 2018.
General and administrative. General and administrative costs increased by $31.6 million during the year ended December 31, 2018, as compared to the year ended December 31, 2017. The increase is driven by costs related to acquisition activity, including the DGE acquisition, and the loss of our ability to charge out certain costs associated with the transfer of operatorship of the Greater Tortue Ahmeyim development project and WCTP Block to BP and Tullow, respectively. No U.S. Gulf of Mexico acquisition related general and administrative costs were included in the 2017 period.
Depletion and depreciation. Depletion and depreciation increased $74.6 million during the year ended December 31, 2018, as compared with the year ended December 31, 2017. The increase is primarily a result the DGE acquisition which added $59.8 million of depletion and depreciation for the U.S. Gulf of Mexico. The remaining increase is related to a higher depletion rate for the TEN fields as 2018 had seven Jubilee and four TEN liftings compared to eight Jubilee and three TEN liftings in 2017. Additionally, the Jubilee Field depletion increased as a result of costs associated with the Mahogany and Teak discovery areas moving into the Jubilee Field's depletable cost basis in the fourth quarter of 2017. No U.S. Gulf of Mexico acquisition related depletion and depreciation costs are included in the 2017 period.
Interest and other financing costs, net. Interest and other financing costs, net increased by $23.6 million primarily a result of a $17.9 million increase in interest related to a higher average interest rate on an increased outstanding debt balance, the result of the DGE acquisition. In addition, we expensed $4.3 million of existing unamortized debt issuance costs and deferred interest in connection with amending the Facility in first quarter 2018 and capitalized interest decreased $2.0 million versus 2017.
Derivatives, net. During the years ended December 31, 2018 and 2017, we recorded a gain and loss of $31.4 million and $60.0 million, respectively, on our outstanding hedge positions. The gain and loss recorded were a result of changes in the forward curve of oil prices during the respective periods.
(Gain) loss on equity method investments, net. (Gain) loss on equity method investments, net resulted in a $72.9 million gain on our equity method investment in KTIPI in 2018, compared to a $6.2 million net loss in 2017, the result of a loss on our equity method investment in Kosmos BP Senegal Limited ("KBSL") which more than offset the gain from KTIPI in 2017. KBSL ceased to be accounted for under the equity method of accounting in November 2017.
Other expenses, net. Other expenses, net decreased $11.8 million primarily related to the recovery of $12.9 million of disputed charges related to the arbitration award against Tullow Ghana in 2018.
Income tax expense (benefit). Income tax expense decreased by $1.8 million during the year ended December 31, 2018, as compared with the year ended December 31, 2017, primarily as a result of higher 2017 taxes due to changes in U.S. tax law, partially offset by higher 2018 pre-tax earnings in Ghana and U.S. Gulf of Mexico. The Company's effective tax rates for the years ended December 31, 2018 and 2017 were 85% and 25%, 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, partially offset by 2018 income from our equity method investment. The effective tax rate in Ghana is impacted by higher oil revenue and lower oil derivative losses, partially offset by higher exploration and production expenses. The

Ghanaian effective tax rate is impacted by the 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.

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Year Ended December 31, 2017 vs. 2016

	Years Ended December 31,		Increase (Decrease)
	2017	2016	
	(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.

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.

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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 transaction 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.

Liquidity and Capital Resources

We are actively engaged in an ongoing process of anticipating and meeting our funding requirements related to our strategy as a full-cycle E&P company. 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.
While we are presently in a strong financial position, commodity prices remain volatile and could negatively impact our ability to generate sufficient operating cash flows to meet our funding requirements. To partially mitigate this price volatility, we maintain a hedging program. 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 up to a contractually agreed cap. Current commodity prices, combined with our hedging program, partner carries and our current liquidity position support our dividend and capital program for 2019.
As such, our 2019 capital budget is based on our exploitation and production plans for Ghana, Equatorial Guinea and the U.S. Gulf of Mexico, our infrastructure-led exploration program in Equatorial Guinea and the U.S. Gulf of Mexico our appraisal activities in our emerging basins and our basin opening exploration across the portfolio.
Our future financial condition and liquidity can be impacted by, among other factors, the success of our exploitation, exploration and appraisal drilling programs, 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 exploitation, 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) which was increased to $1.7 billion (effective January 31,

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2019) after the election to exercise $0.2 billion of additional commitments in the fourth quarter of 2018. The borrowing base calculation includes value related to the Jubilee, TEN, Ceiba and Okume fields.

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, 2018, 2017 and 2016:

	Years Ended December 31,		
	2018	2017	2016
	(In thousands)		
Sources of cash, cash equivalents and restricted cash:			
Net cash provided by operating activities	$260,491	$236,617	$52,077
Return of investment from KTIPI	184,664	—	—
Borrowings under long-term debt	1,175,000	200,000	450,000
Proceeds on sale of assets	13,703	222,068	210
	1,633,858	658,685	502,287
Uses of cash, cash equivalents and restricted cash:			
Oil and gas assets	213,806	140,495	535,975
Other property	7,935	2,858	1,998
Acquisition of oil and gas properties	961,764	—	—
Equity method investment	—	231,280	—
Payments on long-term debt	325,000	250,000	—
Purchase of treasury stock	206,051	2,194	1,981
Deferred financing costs	38,672	67	—
	1,753,228	626,894	539,954
Increase (decrease) in cash, cash equivalents and restricted cash	$(119,370)	$31,791	$(37,667)

Net cash provided by operating activities. Net cash provided by operating activities in 2018 was $260.5 million compared with net cash provided by operating activities of $236.6 million in 2017 and $52 million in 2016, respectively. The increase in cash provided by operating activities in the year ended December 31, 2018 when compared to the same period in 2017 is primarily a result of an increase in oil and gas revenue and a decrease in exploration expenses related to the stacked rig costs and rig option cancellation payment, both recorded during the year ended December 31, 2017. These changes were offset by a lack of LOPI proceeds, an increase in unsuccessful well costs and an increase in payments related to derivative cash settlements. The increase in cash provided by operating activities in the year ended December 31, 2017 when compared to the same period in 2016 was primarily a result of an increase in oil and gas revenue combined with LOPI proceeds, 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.

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The following table presents our liquidity and financial position as of December 31, 2018:

	December 31, 2018 (In thousands)
Cash and cash equivalents	$ 173,515
Restricted cash	12,101
Senior Notes at par	525,000
Drawings under the Facility	1,325,000
Drawings under the Corporate Revolver	325,000
Net debt	$ 1,989,384
Availability under the Facility(1)	$ 375,000
Availability under the Corporate Revolver	$ 75,000
Available borrowings plus cash and cash equivalents	$ 623,515

(1) Includes letter agreements with existing financial institutions, entered into December 2018, which obligated the financial institutions to provide the Company with an additional commitment of $100 million in the aggregate under the Facility effective January 31, 2019.

Capital Expenditures and Investments

We expect to incur capital costs as we:

- drill additional wells and execute exploitation activities in Ghana, Equatorial Guinea and in the U.S. Gulf of Mexico;
- execute infrastructure-led exploration efforts in the U.S. Gulf of Mexico and Equatorial Guinea
- execute appraisal and exploration activities in a number of our exploration license areas; and
- acquire and analyze seismic on existing licenses and purchase seismic over new prospective areas.

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, 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.

2019 Capital Program

We estimate we will spend approximately $425-$475 million of capital, net of carry amounts related to the Mauritania and Senegal transactions with BP, for the year ending December 31, 2019. This capital expenditure budget consists of:

- Approximately 64% related to exploitation and production optimization activities across our Ghana, Equatorial Guinea and Gulf of Mexico assets
- Approximately 19% related to our infrastructure-led exploration and development activities across Equatorial Guinea and the U.S. Gulf of Mexico
- Approximately 2% related to the development of our world-scale discoveries in Mauritania and Senegal

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- Approximately 15% related to basin opening exploration efforts across our portfolio

The ultimate amount of capital we will spend may fluctuate materially based on market conditions and the success of our exploitation and 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 multi-faceted exploration and appraisal drilling programs, 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 exploitation, 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

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. In November 2018, the Company exercised its option with existing financial institutions to provide the Company with an additional commitment of $100 million in the aggregate under the Facility. The borrowing base calculation includes value related to the Jubilee, TEN, Ceiba and Okume fields. 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 $4.1 million of existing unamortized debt issuance costs and deferred interest attributable to those participants was expensed in interest and other financing costs, net. As of December 31, 2018, we have $40.5 million of unamortized issuance costs related to the Facility, which will be amortized over the remaining term of the Facility. In December 2018, the Company entered into letter agreements with existing financial institutions, which provided the Company with an additional commitment of $100 million in the aggregate under the Facility effective January 31, 2019. This took the total commitments to $1.7 billion as of January 31, 2019.

As of December 31, 2018, borrowings under the Facility totaled $1,325.0 million and the undrawn availability under the Facility was $375.0 million, which includes the additional commitments as referenced above.

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, 2018, we had no letters of credit issued under the Facility.

We have 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 September 30, 2018 (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
- 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 August 2018, we amended and restated the Corporate Revolver maintaining the borrowing capacity at $400.0 million, extending the maturity date from November 2018 to May 2022 and lowering the margin 100 basis points to 5%. This resulted in lower commitment fees on the undrawn portion of the total commitments, which is 30% per annum of the respective margin. The Corporate Revolver is available for general corporate purposes and for oil and gas exploration, appraisal and development programs.

As of December 31, 2018, borrowings under the Corporate Revolver totaled $325.0 million and the undrawn availability under the Corporate Revolver was $75.0 million.

Interest is the aggregate of the applicable margin (5.0%), 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 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 August 2018, expires on May 31, 2022. 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, 2018 (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 was $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. In July 2018 and December 2018, the LC Facility size was voluntarily reduced to $40.0 million and$20.0 million, respectively, based on the expiration of several large outstanding letters of credit. As of December 31, 2018, there were seven outstanding letters of credit totaling $14.4 million under the LC Facility. The LC Facility contains customary cross default provisions.

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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 wholly-owned 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, 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 our wholly-owned subsidiary, Kosmos Energy Holdings, pursuant to the terms of the Charge over Shares of Kosmos Energy Holdings dated as of December 20, 2018, among Kosmos Energy Delaware Holdings, LLC, Credit Agricole Corporate and Investment Bank, as Security and Intercreditor Agent, and Wilmington Trust, National Association, as Trustee to the Senior Notes. 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.

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Contractual Obligations

The following table summarizes by period the payments due for our estimated contractual obligations as of December 31, 2018:

	Payments Due By Year(4)						
	Total	2019	2020	2021	2022	2023	Thereafter
Principal debt repayments(1)	$2,175,000	$ —	$ —	$685,600	$614,100	$305,100	$570,200
Interest payments on long-term debt(2)	593,217	147,936	145,347	137,715	73,236	47,528	41,455
Operating leases(3)	36,508	2,775	4,173	3,276	3,326	3,376	19,582

(1) Includes the scheduled principal maturities for the $525.0 million aggregate principal amount of Senior Notes issued in August 2014 and April 2015, borrowings under the Facility and the Corporate Revolver. The scheduled maturities of debt related to the Facility are based on, as of December 31, 2018, our level of borrowings and our estimated future available borrowing base commitment levels in future periods. 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.

(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. The Company's liabilities for asset retirement obligations associated with the dismantlement, abandonment and restoration costs of oil and gas properties are not included. See Note 11 of Notes to the Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding these liabilities.

We currently have a commitment to drill one exploration well in Mauritania and Namibia and two exploration wells in Senegal. Our partner is obligated to fund our share of the cost of the exploration wells, subject to the remaining exploration and appraisal carry covering both our Mauritania and Senegal blocks. In Sao Tome and Principe, we have a 3D seismic requirement of approximately 13,500 square kilometers.

In February 2019, Kosmos and BP signed Carry Advance Agreements with the national oil companies of Mauritania and Senegal which obligate us separately to finance the respective national oil company’s share of certain development costs. Kosmos’ total share for the two agreements combined is up to $239.7 million, which is to be repaid through the national oil companies’ share of future revenues.

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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,
	2019	2020	2021	2022	2023	Thereafter	2018
	(In thousands, except percentages)						
Fixed rate debt:							
Senior Notes	$—	$—	$525,000	$—	$—	$—	$(525,026)
Fixed interest rate	7.88 %	7.88 %	7.88 %	—	—	—	
Variable rate debt:							
Facility(1)	$—	$—	$160,600	$289,100	$305,100	$570,200	$(1,325,000)
Corporate Revolver	—	—	—	325,000	—	—	(325,000)
Weighted average interest rate(2)	6.14 %	5.99 %	5.97 %	6.03 %	6.14 %	6.82 %	

(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, 2018. 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.

(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.

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, 2018, our material off balance sheet arrangements and transactions include operating leases, supplemental bonds for plugging and abandonment 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. 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, 2018 and

2017, 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 Ghana 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, 2018 and 2017, 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.
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

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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. 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.

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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 9—Derivative Financial Instruments and Note 10—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, 2018:

	Derivative Contracts Assets (Liabilities)		
	Commodities	Interest Rates	Total
	(In thousands)		
Fair value of contracts outstanding as of December 31, 2017	$ (97,036)	$ 1,017	$ (96,019)
Acquisition and novation of DGE contracts	(41,139)	—	$ (41,139)
Changes in contract fair value	29,468	492	29,960
Contract maturities	139,451	(1,509)	137,942
Fair value of contracts outstanding as of December 31, 2018	$ 30,744	$ —	$ 30,744

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. Substantially all of our oil sales are indexed against Dated Brent, Eugene Island, Heavy Louisiana Sweet and Mars crude.

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.

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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, 2018:

				Weighted Average Price per Bbl					Asset (Liability) Fair Value at December 31,
Term	Type of Contract	Index	MBbl	Net Deferred Premium Payable/(Receivable)	Swap	Sold Put	Floor	Ceiling	2018(3)
2019									
January — December	Three-way collars	Dated Brent	10,500	$ 1.17	$ —	$ 43.81	$ 53.33	$ 73.58	$ 13,355
January — December	Sold calls(1)	Dated Brent	913	—	—	—	—	80.00	(9,465)
January — December	Swaps	NYMEX WTI	1,747	—	52.31	—	—	—	8,988
January — June	Collars	NYMEX WTI	339	—	—	—	57.77	63.70	3,968
January — December	Collars	Argus LLS	1,000	—	—	—	60.00	88.75	10,390
2020									
January — December	Three-way collars	Dated Brent	2,000	$ —	$ —	$ 50.00	$ 60.00	$ 90.54	$ 9,181
January — December	Sold calls(1)(2)	Dated Brent	8,000	1.17	—	—	—	85.00	(6,108)

(1) Represents call option contracts sold to counterparties to enhance other derivative positions.
(2) Deferred premium payable to be paid January - December 2019.
(3) Fair values are based on the average forward oil prices on December 31, 2018.

In January and February 2019, we entered into three-way collar contracts for 2.0 MMBbl from January 2020 through December 2020 with a sold put price of $40.00 per barrel, a floor price of $55.00 per barrel and a ceiling price of $75.00 per barrel. The contracts are indexed to Dated Brent prices and have a net deferred premium payable of $2.5 million.

At December 31, 2018, our open commodity derivative instruments were in a net asset position of $30.7 million. As of December 31, 2018, a hypothetical 10% price increase in the commodity futures price curves would decrease future pre tax earnings by approximately $45.7 million. Similarly, a hypothetical 10% price decrease would increase future pre tax earnings by approximately $43.9 million.

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Interest Rate Sensitivity

At December 31, 2018, we had indebtedness outstanding under the Facility of $1,325.0 million and the Corporate Revolver of $325.0 million, which bore interest at floating rates. The interest rate on this indebtedness as of December 31, 2018 was approximately 5.8% and 7.5%, respectively. If LIBOR increased 10% at this level of floating rate debt, we would pay an additional $4.2 million in interest expense per year. We pay commitment fees on the $275.0 million of undrawn availability under the Facility and on the $75.0 million of undrawn availability under the Corporate Revolver at December 31, 2018, which are not subject to changes in interest rates.

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Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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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, 2018 and 2017, the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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 28, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Company’s auditor since 2004.

Dallas, Texas

February 28, 2019

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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, 2018, 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, 2018, based on the COSO criteria.

As indicated in the accompanying Index item 9A, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Deep Gulf Energy, which is included in the 2018 consolidated financial statements of the Company and constituted 37% of total assets as of December 31, 2018 and 17% of revenues for the year then ended. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of Deep Gulf Energy.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the 2018 consolidated financial statements of the Company and our report dated February 28, 2019 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 28, 2019

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

	December 31, 2018	2017
Assets		
Current assets:		
Cash and cash equivalents	$173,515	$233,412
Restricted cash	4,527	56,380
Receivables:		
Joint interest billings, net	64,572	134,565
Oil sales	48,164	—
Related party	5,580	780
Other	21,690	25,616
Inventories	84,827	71,861
Prepaid expenses and other	68,040	9,306
Derivatives	38,785	1,682
Total current assets	509,700	533,602
Property and equipment:		
Oil and gas properties, net	3,444,864	2,310,973
Other property, net	14,837	6,855
Property and equipment, net	3,459,701	2,317,828
Other assets:		
Equity method investment	51,896	236,514
Restricted cash	7,574	15,194
Long-term receivables - joint interest billings	19,002	34,941
Deferred financing costs, net of accumulated amortization of $12,065 and $13,951 at December 31, 2018 and December 31, 2017, respectively	8,937	2,510
Deferred tax assets	14,004	22,517
Derivatives	14,312	39
Other	3,063	29,458
Total assets	$4,088,189	$3,192,603
Liabilities and shareholders’ equity		
Current liabilities:		
Accounts payable	$176,540	$141,787
Accrued liabilities	195,596	219,412
Derivatives	12,172	67,531
Total current liabilities	384,308	428,730
Long-term liabilities:		
Long-term debt, net	2,120,547	1,282,797
Derivatives	10,181	30,209
Asset retirement obligations	145,336	66,595
Deferred tax liabilities	477,179	476,548
Other long-term liabilities	9,160	10,612
Total long-term liabilities	2,762,403	1,866,761

Shareholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2018 and December 31, 2017	—	—
Common stock, $0.01 par value; 2,000,000,000 authorized shares; 442,914,675 and 398,599,457 issued at December 31, 2018 and December 31, 2017, respectively	4,429	3,986
Additional paid-in capital	2,341,249	2,014,525
Accumulated deficit	(1,167,193)	(1,073,202)
Treasury stock, at cost, 44,263,269 and 9,188,819 shares at December 31, 2018 and December 31, 2017, respectively	(237,007)	(48,197)
Total shareholders' equity	941,478	897,112
Total liabilities and shareholders' equity	$4,088,189	$3,192,603

See accompanying notes.

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

	Years Ended December 31,		
	2018	2017	2016
Revenues and other income:			
Oil and gas revenue	$886,666	$578,139	$310,377
Gain on sale of assets	7,666	—	—
Other income, net	8,037	58,697	74,978
Total revenues and other income	902,369	636,836	385,355
Costs and expenses:			
Oil and gas production	224,727	126,850	119,367
Facilities insurance modifications, net	6,955	(820)	14,961
Exploration expenses	301,492	216,050	202,280
General and administrative	99,856	68,302	87,623
Depletion and depreciation	329,835	255,203	140,404
Interest and other financing costs, net	101,176	77,595	44,147
Derivatives, net	(31,430)	59,968	48,021
(Gain) loss on equity method investments, net	(72,881)	6,252	—
Other expenses, net	(6,501)	5,291	23,116
Total costs and expenses	953,229	814,691	679,919
Loss before income taxes	(50,860)	(177,855)	(294,564)
Income tax expense (benefit)	43,131	44,937	(10,784)
Net loss	$(93,991)	$(222,792)	$(283,780)
Net loss per share:			
Basic	$(0.23)	$(0.57)	$(0.74)
Diluted	$(0.23)	$(0.57)	$(0.74)
Weighted average number of shares used to compute net loss per share:			
Basic	404,585	388,375	385,402
Diluted	404,585	388,375	385,402

See accompanying notes.

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

	Common Stock		Additional Paid-in	Accumulated	Treasury	
	Shares	Amount	Capital	Deficit	Stock	Total
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
Acquisition of oil and gas properties	34,994	350	307,594	—	—	307,944
Equity-based compensation	—	—	36,464	—	—	36,464
Restricted stock awards and units	9,322	93	(93)	—	—	—
Purchase of treasury stock	—	—	(17,241)	—	(188,810)	(206,051)
Net loss	—	—	—	(93,991)	—	(93,991)
Balance as of December 31, 2018	442,915	$ 4,429	$ 2,341,249	$ (1,167,193)	$ (237,007)	$ 941,478

See accompanying notes.

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

	Years Ended December 31,		
	2018	2017	2016
Operating activities			
Net loss	$(93,991)	$(222,792)	$(283,780)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depletion, depreciation and amortization	339,214	265,407	150,608
Deferred income taxes	9,145	9,505	(23,561)
Unsuccessful well costs	123,199	43,201	6,079
Change in fair value of derivatives	(29,960)	71,822	46,559
Cash settlements on derivatives, net (including $(137.1) million and $38.7 million and $188.0 million on commodity hedges during 2018, 2017, and 2016)	(137,942)	25,888	188,895
Equity-based compensation	35,230	39,913	40,084
Gain on sale of assets	(7,666)	—	—
Loss on extinguishment of debt	4,324	—	—
Loss on equity method investment, net / (Undistributed equity in earnings)	(45)	6,252	—
Other	2,865	5,952	13,355
Changes in assets and liabilities:			
(Increase) decrease in receivables	175,954	29,365	(20,558)
(Increase) decrease in inventories	8,848	1,653	(4,107)
(Increase) decrease in prepaid expenses and other	(18,731)	(31,710)	17,557
Increase (decrease) in accounts payable	7,440	(94,434)	(75,487)
Increase (decrease) in accrued liabilities	(157,393)	86,595	(3,567)
Net cash provided by operating activities	260,491	236,617	52,077
Investing activities			
Oil and gas assets	(213,806)	(140,495)	(535,975)
Other property	(7,935)	(2,858)	(1,998)
Acquisition of oil and gas properties, net of cash acquired	(961,764)	—	—
Equity method investment	—	(231,280)	—
Return of investment from KTIPI	184,664	—	—
Proceeds on sale of assets	13,703	222,068	210
Net cash used in investing activities	(985,138)	(152,565)	(537,763)
Financing activities			
Borrowings under long-term debt	1,175,000	200,000	450,000
Payments on long-term debt	(325,000)	(250,000)	—
Purchase of treasury stock / tax withholdings	(206,051)	(2,194)	(1,981)
Deferred financing costs	(38,672)	(67)	—
Net cash provided by (used in) financing activities	605,277	(52,261)	448,019
Net increase (decrease) in cash, cash equivalents and restricted cash	(119,370)	31,791	(37,667)
Cash, cash equivalents and restricted cash at beginning of period	304,986	273,195	310,862
Cash, cash equivalents and restricted cash at end of period	$185,616	$304,986	$273,195

Supplemental cash flow information
Cash paid for:

Interest, net of capitalized interest	$83,831	$55,381	$27,860
Income taxes	$45,984	$48,815	$13,997
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)	$—
Common stock issued for acquisition of oil and gas properties	$307,944	$—	$—

See accompanying notes.

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KOSMOS ENERGY LTD.
Notes to Consolidated Financial Statements
1. Organization
Kosmos Energy Ltd. changed its jurisdiction of incorporation from Bermuda to the State of Delaware (the "Redomestication") in December 2018. All outstanding common shares of Kosmos Energy Ltd., an exempted company incorporated pursuant to the laws of Bermuda, were automatically converted by operation of law, on a one-for-one basis, into shares of common stock of Kosmos Energy Ltd., a company incorporated pursuant to the laws of Delaware. The number of shares of the Company's common stock outstanding immediately after the Redomestication was the same as the number of common shares of Kosmos Energy Ltd. outstanding immediately prior to the Redomestication. Kosmos Energy Ltd. was originally incorporated pursuant to the laws of Bermuda in January 2011 to become a holding company for Kosmos Energy Holdings. As part of the Redomestication, we transferred all of our equity interests in Kosmos Energy Holdings to a new, wholly-owned subsidiary, Kosmos Energy Delaware Holdings, LLC, a Delaware limited liability company. 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," and similar terms refer to Kosmos Energy Ltd. and its wholly-owned subsidiaries, unless the context indicates otherwise.
Kosmos is a full-cycle deepwater independent oil and gas exploration and production company focused along the Atlantic Margins. Our key assets include production offshore Ghana, Equatorial Guinea and U.S. Gulf of Mexico, as well as a world-class gas development offshore Mauritania and Senegal. We also maintain a sustainable exploration program balanced between proven basin infrastructure-led exploration (Equatorial Guinea and U.S. Gulf of Mexico), emerging basins (Mauritania, Senegal and Suriname) and frontier basins (Cote d'Ivoire, Namibia and Sao Tome and Principe). Kosmos is listed on the New York Stock Exchange ("NYSE") and London Stock Exchange ("LSE") and is traded under the ticker symbol KOS.
Kosmos is engaged in a single line of business, which is the exploration and production of oil and natural gas. We have operations in four geographic areas: Ghana, Equatorial Guinea, Mauritania/Senegal and the United States of America.
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 Company'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 Company are integral to the Company'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.

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Cash, Cash Equivalents and Restricted Cash

	December 31,		
	2018	2017	2016
	(In thousands)		
Cash and cash equivalents	$173,515	$233,412	$194,057
Restricted cash - current	4,527	56,380	24,506
Restricted cash - long-term	7,574	15,194	54,632
Total cash, cash equivalents and restricted cash shown in the consolidated statements of cash flows	$185,616	$304,986	$273,195

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 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, 2018 and 2017, we had $4.5 million and $31.6 million, respectively, of current restricted cash and $7.4 million and $15.2 million, respectively, of long term restricted cash used to cash collateralize performance guarantees related to our petroleum contracts. As of December 31, 2018, we also had $0.2 million in other long-term restricted cash.

In addition, prior to our reserves-based debt facility (the “Facility”) being amended and restated in February 2018, we were required to maintain a restricted cash balance that was 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 was greater. As of December 31, 2017, we had $24.8 million in current restricted cash to meet this requirement. Under the amended and restated Facility, we are no longer required to maintain a restricted cash balance provided we are compliant with certain financial covenant ratios.

Receivables

Our receivables consist of joint interest billings, oil and gas sales, related party and other receivables. For our oil sales receivable in Ghana, 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. We had an allowance for doubtful accounts of $1.2 million and zero in current joint interest billings receivables as of December 31, 2018 and 2017, respectively.

Inventories

Inventories consisted of $83.4 million (including $22.1 million acquired through the Deep Gulf Energy, (together with its subsidiaries "DGE") acquisition) and $63.5 million of materials and supplies and $1.4 million and $8.4 million of hydrocarbons as of December 31, 2018 and 2017, 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 $0.3 million, $0.9 million and $14.9 million during the years ended December 31, 2018, 2017 and 2016 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

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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 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 or in service 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

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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 have used 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. 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. 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, 2018 and 2017, we had no oil and gas imbalances recorded in our consolidated financial statements.

Our oil and gas revenues are recognized when production has been sold to a purchaser at a fixed or determinable price, title has transferred and collectability is probable. Certain 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.

Oil and gas revenue is composed of the following:

	Years Ended December 31,		
	2018	2017	2016
Revenues from contracts with customers - Ghana	$741,033	$590,642	$307,837
Revenues from contracts with customers - U.S. Gulf of Mexico	147,596	—	—
Provisional oil sales contracts	(1,963)	(12,503)	2,540
Oil and gas revenue	$886,666	$578,139	$310,377

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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. In November 2018, Kosmos repurchased 35 million shares of our common stock from funds affiliated with Warburg Pincus LLC in a privately negotiated transaction at a price per share of $5.38. The total aggregate purchase price for the share repurchase was approximately $188 million. 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. As of December 2018, SAB 118 provisional period has expired and the Company has no further provisional amounts recorded in our financial statements.

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 international operations. For our U.S. Gulf of Mexico operations, crude oil and natural gas are transported to customers using third-party pipelines. For the year ended December 31, 2018, revenue from Phillips 66 Company made up approximately 11% of our total consolidated revenue and was included in our U.S. Gulf of Mexico segment.

Recent Accounting Standards

Recently Adopted

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)," which supersedes the revenue recognition requirements in ASC 605, "Revenue Recognition," and most industry-specific guidance. ASU 2014-09 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 2014-09 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. ASU 2014-09 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. Entities have the

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option of using either a full retrospective or modified retrospective approach to adopt ASU 2014-09. The Company adopted the new standard during the first quarter of 2018 using the modified retrospective approach and there is no impact to our previously recorded revenue under the new standard.

In March 2018, the FASB issued ASU 2018-05, "Income Taxes (Topic 740)." ASU 2018-05 was issued to include amendments to SEC paragraphs pursuant to SEC Staff Accounting Bulletin No. 118 ("SAB 118") and addresses certain circumstances that may arise for registrants in accounting for the income tax effects of the Tax Cut and Jobs Act (the "Tax Reform Act"), including when certain income tax effects of the Tax Reform Act are incomplete by the time the financial statements are issued. The Company adopted the new standard during the first quarter of 2018 and there was no material impact to our financial statements.

Not Yet Adopted

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)." ASU 2016-02 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. In July 2018, the FASB issued ASU 2018-11, which added a transition option permitting entities to apply the provisions of the new standard at its adoption date instead of the earliest comparative period presented in the consolidated financial statements. Under this transition option, comparative reporting would not be required, and the provisions of the standard would be applied prospectively to leases in effect at the date of adoption. The Company intends to elect this transitional practical expedient.

In the normal course of business, the Company enters into various lease agreements for real estate and equipment related to its exploration, development and production activities that are currently accounted for as operating leases. The Company continues to evaluate contracts that exist as of the adoption date and performing the necessary calculations to determine the balance sheet impact. At this time, the Company cannot reasonably estimate the financial impact this will have on its consolidated financial statements; however, the Company believes adoption and implementation of this ASU will significantly impact its balance sheet, resulting in an increase in both assets and liabilities relating to its leasing activities.

3. Acquisitions and Divestitures

2018 Transactions

In March 2018, as part of our alliance with BP p.l.c ("BP"), we entered into petroleum contracts covering Blocks 10 and 13 with the Democratic Republic of Sao Tome and Principe. We presently have a 35% participating interest in the blocks and the operator, BP, holds a 50% participating interest. The national petroleum agency, Agencia Nacional Do Petroleo De Sao Tome E Principe ("ANP-STP") has a 15% carried interest in the blocks through exploration. The petroleum contracts cover approximately 13,600 square kilometers, with a first exploration period of four years from the effective date (March 2018). The exploration periods can be extended an additional four years at our election subject to fulfilling specific work obligations. The first exploration period work programs include a 13,500 square kilometer 3D seismic acquisition requirement across the two blocks.

In June 2018, we completed a farm-in agreement with a subsidiary of Ophir Energy plc ("Ophir") for Block EG-24, offshore Equatorial Guinea, whereby we acquired a 40% non-operated participating interest. As part of the agreement, we reimbursed a portion of Ophir's previously incurred exploration costs and will fully carry Ophir's share of the costs of a planned 3D seismic program as well as pay a disproportionate share of the well commitment should we enter the second exploration sub-period. The petroleum contract covers approximately 3,500 square kilometers, with a first exploration period of three years from the effective date (March 2018) which can be extended up to four additional years at our election subject to fulfilling specific work obligations. The first exploration period work program includes a 3,000 square kilometer 3D seismic acquisition requirement which was completed in November 2018. In January

2019, we entered into an agreement to acquire Ophir's remaining interest in the block, subject to customary governmental approvals, which will result in Kosmos owning an 80% interest in Block EG-24.

In September 2018, we completed the acquisition of DGE, a deepwater company operating in the U.S. Gulf of Mexico, from First Reserve Corporation and other shareholders for a total consideration of $1.275 billion, comprised of $952.6 million in cash, $307.9 million in Kosmos common stock and $14.9 million of transaction related costs. We funded the cash portion of the purchase price using cash on hand and drawings under our existing credit facilities. We also received $200.0 million of additional firm commitments under the Facility, which provided further liquidity to the Company. The DGE acquisition was accounted for under the asset acquisition method and the purchase price allocation is shown below. The purchase price allocation was based on the estimated relative fair value of identifiable assets acquired and liabilities assumed.

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The estimated fair value measurements of oil and gas assets acquired and asset retirement obligations liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair value of oil and gas properties and asset retirement obligations were measured using the discounted cash flow technique of valuation. Significant inputs to the valuation of oil and gas properties include estimates of: (i) reserves, (ii) future operating and development costs, (iii) future commodity prices, (iv) future plugging and abandonment costs, (v) estimated future cash flows, and (vi) a market-based weighted average cost of capital rate.

	Purchase Price Allocation (in thousands)
Fair value of assets acquired:	
Proved oil and gas properties	$1,037,511
Unproved oil and gas properties	298,159
Accounts receivable and other	180,989
Total assets acquired	$1,516,659
Fair value of liabilities assumed:	
Accrued liabilities and other	$126,530
Asset retirement obligations	74,482
Derivative liabilities	40,265
Total liabilities assumed	$241,277
Purchase price:	
Cash consideration paid	$952,586
Fair value of common stock(1)	307,944
Transaction related costs	14,852
Total purchase price	$1,275,382

(1) Based on 34,993,585 shares of common stock issued at a price of $8.80 per share, which was the opening Kosmos common stock price on September 14, 2018, the closing date of the acquisition.

As a result of the DGE acquisition, we have included $147.6 million of revenues and $30.5 million of direct operating expenses in our consolidated statements of operations for the period from September 14, 2018 to December 31, 2018.

In October 2018, Kosmos entered into a strategic exploration alliance with Shell Exploration Company B.V. (“Shell”) to jointly explore in Southern West Africa. Initially the alliance will focus on Namibia where Kosmos has completed a farm-in to Shell's acreage in PEL 39, and Sao Tome and Principe where we have entered into exclusive negotiations for Shell to take an interest in Kosmos’ acreage in Blocks 5, 6, 11, and 12. As part of the alliance, the two companies will also jointly evaluate opportunities in adjacent geographies. This alliance is consistent with Kosmos’ strategy of partnering with supermajors to leverage complementary skill sets. Shell has deep expertise in carbonate plays, while Kosmos brings significant knowledge of the Cretaceous in West Africa. Furthermore, by working with Shell, Kosmos has a partner with the expertise to efficiently move exploration successes through the development stage.

2017 Transactions

In December 2016, we announced transactions with affiliates of 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 Kosmos BP Senegal Limited ("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

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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.

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 reimbursed Tullow a portion of past and interim period costs and will 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 was accounted for as an equity method investment. See Note 7—Equity Method Investments for further discussion of our investment in KTIPI.

In October 2017, we entered into petroleum contracts covering Blocks EG-21, S, and W with the Republic of Equatorial Guinea. We had an 80% participating interest and were the operator in all three blocks. In August 2018, we closed a farm-out agreement with Trident, whereby they acquired a 40% participating interest in blocks EG-21, S, and W, resulting in a $7.7 million gain. After giving effect to the farm-out agreement, we hold a 40% participating interest and remain the operator in all three blocks. The Equatorial Guinean national oil company, Guinea Equatorial De Petroleos ("GEPetrol"), 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 effective date (March 2018). The first exploration period consists of two sub-periods of three and two years, respectively. The first exploration sub-period work program includes a 6,000 square kilometer 3D seismic acquisition requirement across the three blocks.

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.

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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 funded 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 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 funded the remainder of the seismic program.

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 August 2018, we provided to the Office National Des Hydrocarbures et des Mines ("ONHYM") a notice to abandon the Essaouira Offshore block, located offshore Morocco, at the end of the current exploration phase (November 2018).

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.

4. Joint Interest Billings and Related Party Receivables

The Company’s joint interest billings consist of receivables from partners with interests in common oil and gas properties operated by the Company. 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 are being reimbursed for such costs plus interest out of a portion of GNPC’s TEN production revenues. As of December 31, 2018 and 2017, the current portion of the joint interest billing receivables due from GNPC for the TEN fields development costs were $14.0 million and $15.2 million, respectively, and the long-term portion were

$14.0 million and $31.6 million.

The Company's related party receivables consists primarily of receivables from Trident who, until January 2019, owned a 50% interest in KTIPI. As of December 31, 2018 the balance due from Trident consists of $5.6 million related to joint interest billings for the exploration blocks and Kosmos' support of KTIPI operations.

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5. Property and Equipment

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

	December 31,	
	2018	2017
	(In thousands)	
Oil and gas properties:		
Proved properties	$2,773,276	$1,653,616
Unproved properties	759,472	465,109
Support equipment and facilities	1,463,213	1,427,054
Total oil and gas properties	4,995,961	3,545,779
Accumulated depletion	(1,551,097)	(1,234,806)
Oil and gas properties, net	3,444,864	2,310,973
Other property	51,987	39,405
Accumulated depreciation	(37,150)	(32,550)
Other property, net	14,837	6,855
Property and equipment, net	$3,459,701	$2,317,828

We recorded depletion expense of $316.3 million, $244.9 million and $131.5 million and depreciation expense of $4.6 million, $3.4 million and $3.5 million for the years ended December 31, 2018, 2017 and 2016, 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, 2018, 2017 and 2016. The table excludes $65.6 million, $43.2 million and $2.4 million in costs that were capitalized and subsequently expensed during the same year for the years ended December 31, 2018, 2017 and 2016, 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,		
	2018	2017	2016
	(In thousands)		
Beginning balance	$410,113	$734,463	$426,881
Additions to capitalized exploratory well costs pending the determination of proved reserves	10,518	69,567	307,582
Additions associated with the acquisition of DGE	26,224	—	—
Reclassification due to determination of proved reserves(1)	(26,224)	(176,881)	—
Divestitures(2)	—	(206,400)	—
Contribution of oil and gas property to equity method investment - KBSL	—	(131,764)	—
Dissolution of equity method investment - KBSL	—	121,128	—
Capitalized exploratory well costs charged to expense(3)	(52,966)	—	—
Ending balance	$367,665	$410,113	$734,463

(1) Represents the reclassification of Nearly Headless Nick well costs associated with the DGE acquisition in 2018 and inclusion of the Mahogany and Teak discoveries in the Jubilee Unit in 2017.

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

(3) Primarily related to Akasa and Wawa as we wrote off $38.1 million and $13.6 million, respectively, of previously capitalized costs exploratory well costs to exploration expense during the third quarter of 2018. These impairments are included in our Ghana segment.

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,		
	2018	2017	2016
	(In thousands, except well counts)		
Exploratory well costs capitalized for a period of one year or less	$—	$67,159	$279,809
Exploratory well costs capitalized for a period of one to two years	299,253	291,252	244,804
Exploratory well costs capitalized for a period of three years or longer	68,412	51,702	209,850
Ending balance	$367,665	$410,113	$734,463
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	3	5	5

As of December 31, 2018, the projects with exploratory well costs capitalized for more than one year since the completion of drilling are related to the Greater Tortue discovery which crosses the Mauritania and Senegal maritime border and 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.

Greater Tortue Ahmeyim Project — In May 2015, we completed the Tortue-1 exploration well in Block C8 offshore Mauritania which encountered hydrocarbon pay. Two additional wells were drilled in the Greater Tortue Ahmeyim project 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 Ahmeyim project. Data acquired from the drill stem test was used to further optimize field development and to refine process design parameters critical to the FEED process. In December 2018, we made a final investment decision to develop the Greater Tortue Ahmeyim project.

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 is expected be made.

Yakaar and Teranga Discoveries — In May 2016, we completed the Teranga-1 exploration well in the Cayar Offshore Profond block offshore Senegal which encountered hydrocarbon pay. In June 2017, we completed the Yakaar-1 exploration well in the Cayar Offshore Profond block offshore Senegal which encountered hydrocarbon pay. In November 2017, an integrated Yakaar-Teranga appraisal plan was submitted. An appraisal well is scheduled in 2019 to further evaluate the discovery. Following additional evaluation, a decision regarding commerciality is expected to be made.

7. Equity Method Investments

Kosmos BP Senegal Limited

As part of our transaction in Senegal with BP in February 2017, our participating interests in the Cayar Offshore Profond and Saint Louis Offshore Profond blocks ("Senegal Blocks") were contributed to KBSL, a corporate joint venture in which we owned a 50.01% interest which was accounted for under the equity method of accounting.

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

Our initial contribution to KBSL was $133.9 million, which was recorded at our carrying costs. Our share of losses in KBSL during the period it was accounted for as an equity method investment is reflected in our consolidated statements of operations as (Gain) loss on equity method investments, net. During the year ended December 31, 2017, we recognized $11.5 million related to our share of losses in KBSL.

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Equatorial Guinea

As part of our acquisition of KTIPI, a corporate joint venture entity in which we owned a 50% interest, we acquired an indirect participating interest in 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, 2018	December 31, 2017
	(In thousands)	
Assets		
Total current assets	$149,950	$179,070
Property and equipment, net	271,627	345,611
Other assets	21	567
Total assets	$421,598	$525,248
Liabilities and shareholders' deficit		
Total current liabilities	$226,311	$106,769
Total long term liabilities	536,178	565,591
Shareholders' deficit:		
Total shareholders' deficit	(340,891)	(147,112)
Total liabilities and shareholders' deficit	$421,598	$525,248

	Year Ended December 31, 2018	Period November 28, 2017 through December 31, 2017
	(In thousands)	
Revenues and other income:		
Oil and gas revenue	$721,299	$54,615
Other income	(477)	294
Total revenues and other income	720,822	54,909
Costs and expenses:		
Oil and gas production	147,685	15,509
Depletion and depreciation	126,983	10,738
Other expenses, net	429	(19)
Total costs and expenses	275,097	26,228
Income before income taxes	445,725	28,681
Income tax expense	156,981	6,588
Net income	$288,744	$22,093
Kosmos' share of net income	$144,372	$11,046
Basis difference amortization(1)	71,491	5,812

Equity in earnings - KTIPI	$72,881	$5,234

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(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, 2018, 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. Our initial investment has been increased for our net share of equity in earnings as adjusted for our basis differential and reduced by cash dividends received. During the year ended December 31, 2018, we received $257.5 million of cash dividends from KTIPI.

With an effective date of January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.375% undivided interest in the Ceiba Field and Okume Complex. As a result, our interest in the Ceiba Field and Okume Complex will be accounted for under the proportionate consolidation method of accounting going forward.

8. Debt

	December 31,	
	2018	2017
	(In thousands)	
Outstanding debt principal balances:		
Facility	$1,325,000	$800,000
Corporate Revolver	325,000	—
Senior Notes	525,000	525,000
Total	2,175,000	1,325,000
Unamortized deferred financing costs and discounts(1)	(54,453)	(42,203)
Long-term debt, net	$2,120,547	$1,282,797

(1) Includes $40.5 million and $23.6 million of unamortized deferred financing costs related to the Facility and $14.0 million and $18.6 million of unamortized deferred financing costs and discounts related to the Senior Notes as of December 31, 2018 and December 31, 2017, respectively.

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. In November 2018, the Company exercised its option with existing financial institutions to provide the Company with an additional commitment of $100 million in the aggregate under the Facility. The borrowing base calculation includes value related to the Jubilee, TEN, Ceiba and Okume fields. 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 $4.1 million of existing unamortized debt issuance costs and deferred interest attributable to those participants was expensed in interest and other financing costs, net. As of December 31, 2018, we have $40.5 million of unamortized issuance costs related to the Facility, which will be amortized over the remaining term of the Facility. In December 2018, the Company entered into letter agreements with existing financial institutions, which provided the Company with an additional commitment of $100 million in the aggregate under the Facility effective January 31, 2019. This took the total commitments to $1.7 billion as of January 31, 2019.

As of December 31, 2018, borrowings under the Facility totaled $1,325.0 million and the undrawn availability under the Facility was $375.0 million, which includes the additional commitments as referenced above. 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. As part of the amendment and restatement process in February 2018, commitment fees were lowered from 40% 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

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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, 2018, 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, as amended. The borrowing base amount is based on the sum of the net present value 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, 2018 (the most recent assessment date).

Corporate Revolver

In August 2018, we amended and restated the Corporate Revolver maintaining the borrowing capacity at $400.0 million, extending the maturity date from November 2018 to May 2022 and lowering the margin 100 basis points to 5%. This resulted in lower commitment fees on the undrawn portion of the total commitments, which is 30% per annum of the respective margin. The Corporate Revolver is available for general corporate purposes and for oil and gas exploration, appraisal and development programs. As of December 31, 2018, we have $8.9 million of net deferred financing costs related to the Corporate Revolver, which will be amortized over the remaining term. These deferred financing costs are included in the Other assets section of our consolidated balance sheets.

As of December 31, 2018, borrowings under the Corporate Revolver totaled $325.0 million and the undrawn availability under the Corporate Revolver was $75.0 million.

Interest is the aggregate of the applicable margin (5.0%); 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 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 August 2018, expires on May 31, 2022. 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, 2018 (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 was $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

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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. In July 2018 and December 2018, the LC Facility size was voluntarily reduced to $40.0 million and$20.0 million, respectively, based on the expiration of several large outstanding letters of credit. As of December 31, 2018, there were seven outstanding letters of credit totaling $14.4 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 wholly-owned 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, 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.

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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 our wholly-owned subsidiary, Kosmos Energy Holdings, pursuant to the terms of the Charge over Shares of Kosmos Energy Delaware Holdings, LLC dated as of December 20, 2018, among Kosmos Energy Delaware Holdings, LLC, Credit Agricole Corporate and Investment Bank, as Security and Intercreditor Agent, and Wilmington Trust, National Association, as Trustee to the Senior Notes. 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, 2018, the estimated repayments of debt during the five years and thereafter are as follows:

	Payments Due by Year						
	Total	2019	2020	2021	2022	2023	Thereafter
	(In thousands)						
Principal debt repayments(1)	$2,175,000	$ —	$ —	$685,600	$614,100	$305,100	$570,200

(1) Includes the scheduled principal maturities for the $525.0 million aggregate principal amount of Senior Notes issued in August 2014 and April 2015, borrowings under the Facility and the Corporate Revolver. The scheduled maturities of debt related to the Facility are based on, as of December 31, 2018, our level of borrowings and our estimated future available borrowing base commitment levels in future periods. 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.

Interest and other financing costs, net

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

	Years Ended December 31,		
	2018	2017	2016
	(In thousands)		
Interest expense	$114,134	$92,687	$89,029
Amortization—deferred financing costs	9,379	10,204	10,204
Loss on extinguishment of debt	4,324	—	—
Capitalized interest	(28,331)	(30,282)	(59,803)
Deferred interest	(1,138)	2,577	(581)
Interest income	(3,455)	(3,422)	(1,954)
Other, net	6,263	5,831	7,252
Interest and other financing costs, net	$101,176	$77,595	$44,147

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 non-performance risk in the fair value measurement of our derivative contracts as required by ASC 820—Fair Value Measurements and Disclosures.

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Oil Derivative Contracts

The following table sets forth the volumes in barrels underlying the Company's outstanding oil derivative contracts and the weighted average prices per Bbl for those contracts as of December 31, 2018. Volumes and weighted average prices are net of any offsetting derivative contracts entered into.

				Weighted Average Price per Bbl				
Term	Type of Contract	Index	MBbl	Net Deferred Premium Payable/(Receivable)	Swap	Sold Put	Floor	Ceiling
2019:								
January — December	Three-way collars	Dated Brent	10,500	$1.17	$ —	$43.81	$53.33	$73.58
January — December	Sold calls(1)	Dated Brent	913	—	—	—	—	80.00
January — December	Swaps	NYMEX WTI	1,747	—	52.31	—	—	—
January — June	Collars	NYMEX WTI	339	—	—	—	57.77	63.70
January — December	Collars	Argus LLS	1,000	—	—	—	60.00	88.75
2020:								
January — December	Three-way collars	Dated Brent	2,000	$—	$ —	$50.00	$60.00	$90.54
January — December	Sold calls(1)(2)	Dated Brent	8,000	1.17	—	—	—	85.00

(1) Represents call option contracts sold to counterparties to enhance other derivative positions.
(2) Deferred premium payable to be paid January - December 2019.

In January and February 2019, we entered into three-way collar contracts for 2.0 MMBbl from January 2020 through December 2020 with a sold put price of $40.00 per barrel, a floor price of $55.00 per barrel and a ceiling price of $75.00 per barrel. The contracts are indexed to Dated Brent prices and have a net deferred premium payable of $2.5 million.

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, 2018 and 2017 and gain/(loss) from derivatives during the years ended December 31, 2018, 2017 and 2016.

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) December 31, 2018	2017
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative assets:			
Commodity(1)	Derivatives assets—current	$38,785	$665
Interest rate	Derivatives assets—current	—	1,017
Commodity(2)	Derivatives assets—long-term	14,312	39
Derivative liabilities:			
Commodity(3)	Derivatives liabilities—current	(12,172)	(67,531)
Commodity(4)	Derivatives liabilities—long-term	(10,181)	(30,209)
Total derivatives not designated as hedging instruments		$30,744	$(96,019)

(1) Includes $0.4 million and zero as of December 31, 2018 and December 31, 2017, respectively which represents our provisional oil sales contract. Also, includes net deferred premiums payable of $1.6 million and net deferred premiums receivable of $0.8 million related to commodity derivative contracts as of December 31, 2018 and 2017, respectively.

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(2) Includes net deferred premiums payable of $1.3 million and net deferred premiums receivable of $0.1 million related to commodity derivative contracts as of December 31, 2018 and 2017, respectively.
(3) Includes net deferred premiums payable of $18.0 million and $5.6 million related to commodity derivative contracts as of December 31, 2018 and 2017, respectively.
(4) Includes net deferred premiums payable of $0.5 million and $4.8 million related to commodity derivative contracts as of December 31, 2018 and 2017, respectively.

Type of Contract	Location of Gain/(Loss)	Amount of Gain/(Loss) Years Ended December 31, 2018	2017	2016
		(In thousands)		
Derivatives not designated as hedging instruments:				
Commodity(1)	Oil and gas revenue	$(1,963)	$(12,502)	$2,538
Commodity	Derivatives, net	31,430	(59,968)	(48,021)
Interest rate	Interest expense	493	648	(1,076)
Total derivatives not designated as hedging instruments		$29,960	$(71,822)	$(46,559)

(1) 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, 2018 and 2017, 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, 2018 and 2017, for each fair value hierarchy level:

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	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, 2018				
Assets:				
Commodity derivatives	$ —	$ 53,097	$ —	$ 53,097
Liabilities:				
Commodity derivatives	—	(22,353)	—	(22,353)
Total	$ —	$ 30,744	$ —	$ 30,744
December 31, 2017				
Assets:				
Commodity derivatives	$ —	$ 704	$ —	$ 704
Interest rate derivatives	—	1,017	—	1,017
Liabilities:				
Commodity derivatives	—	(97,740)	—	(97,740)
Total	$ —	$ (96,019)	$ —	$ (96,019)

The book values of cash and cash equivalents and restricted cash approximate fair value based on Level 1 inputs. Joint interest billings, oil sales, related party 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, NYMEX WTI or Argus LLS oil prices. The values attributable to our oil derivatives are based on (i) the contracted notional volumes, (ii) independent active futures price quotes for the respective index, (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 the respective index. 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 the respective index over the term of the pricing period designated in the sales contract and the spot price on the lifting date.

Interest Rate Derivatives

Our interest rate derivatives consisted of interest rate swaps, whereby the Company paid a fixed rate of interest and the counterparty paid a variable LIBOR based rate, and capped interest rate swaps, whereby the Company paid a fixed rate of interest if LIBOR is below the cap, and paid 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 were 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.

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Debt

The following table presents the carrying values and fair values at December 31, 2018 and 2017:

	December 31, 2018		December 31, 2017	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Senior Notes	$511,873	$525,026	$507,600	$542,472
Corporate Revolver	325,000	325,000	—	—
Facility	1,325,000	1,325,000	800,000	800,000
Total	$2,161,873	$2,175,026	$1,307,600	$1,342,472

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,	
	2018	2017
	(In thousands)	
Asset retirement obligations:		
Beginning asset retirement obligations	$66,595	$63,574
Additions associated with the acquisition of DGE	74,482	—
Liabilities incurred during period	5,311	—
Liabilities settled during period	(3,345)	—
Revisions in estimated retirement obligations	—	(3,945)
Accretion expense	8,910	6,966
Ending asset retirement obligations	$151,953	$66,595

The asset retirement obligations reflect the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with our oil and gas properties. The Company utilizes current cost experience to estimate the expected cash outflows for retirement obligations. The Company estimates the ultimate productive life of the properties, a risk-adjusted discount rate, and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation, a corresponding adjustment is made to the oil and gas property balance.

12. Equity based Compensation

Restricted Stock Awards and Restricted Stock Units

Our Long-Term Incentive Plan ("LTIP") 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 2018 and January 2015, the board of directors approved amendments to the plan which added 11.0 million and 15.0 million shares, respectively, to the plan which were approved at the corresponding Annual General Meeting. The LTIP as amended provides for the issuance of 50.5 million shares pursuant to awards under the plan. As of December 31, 2018, the Company had approximately 15.2 million shares that remain available for issuance under the LTIP.

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 $35.2 million, $40.0 million and $40.1 million during the years ended December 31, 2018, 2017 and 2016, respectively. The total tax benefit for the years ended December 31, 2018, 2017 and 2016 was $6.6 million, $13.2 million and $13.0 million, respectively. Additionally, we expensed a net tax shortfall (windfall) related to equity based compensation of $(0.4) million, $3.1 million and $5.5 million for the years

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ended December 31, 2018, 2017 and 2016, respectively. The fair value of awards vested during 2018, 2017 and 2016 was approximately $85.1 million, $21.2 million, and $14.4 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 a three year period. 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, 2018:

	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, 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	—	—
Granted	—	—	—	—
Forfeited	—	—	—	—
Vested	(220)	8.64	—	—
Outstanding at December 31, 2018:	—	—	—	—

The following table reflects the outstanding restricted stock units as of December 31, 2018:

	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, 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
Granted	2,402	7.07	8,111	12.38
Forfeited	(229)	6.40	(302)	8.95
Vested	(2,241)	6.95	(9,545)	13.75
Outstanding at December 31, 2018:	4,115	6.42	6,716	9.02

As of December 31, 2018, total equity based compensation to be recognized on unvested restricted stock units is $33.9 million over a weighted average period of 2.0 years.

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For restricted stock units with a combination of market and service vesting criteria, the number of shares of common stock 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 200% of the awards granted. The grant date fair value ranged from $4.83 to $15.71 per award. 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 44.0% to 53.0%. The risk free interest rate was based on the U.S. treasury rate for a term commensurate with the expected life of the grant ranged from 0.7% to 2.2% for restricted stock units.

In January 2019, we granted 2.6 million service vesting restricted stock units and 2.8 million market and service vesting restricted stock units to our employees under our long-term incentive plan. We expect to recognize approximately $32.0 million of non-cash compensation expense related to these grants over the next three years.

13. Income Taxes

Kosmos Energy Ltd. changed its jurisdiction of incorporation from Bermuda to the State of Delaware in December 2018. The company was not subject to taxation at the parent company level for the years ended December 31, 2017 and 2016. 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.

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.

SAB 118 was issued in January 2018 to address situations where certain aspects of the Tax Reform Act are unclear at issuance of the registrant's financial statements for the reporting period in which the Jobs Act became law. SAB 118 allowed us to record provisional amounts during a one-year measurement period that ended in December 2018. As of December 31, 2018, there are no provisional tax amounts recorded in our financial statements.

The components of loss before income taxes were as follows:

	Years Ended December 31,		
	2018	2017	2016
	(In thousands)		
United States	$41,026	$6,068	$5,083
Bermuda	(73,979)	(66,914)	(63,749)
Foreign—other	(17,907)	(117,009)	(235,898)
Loss before income taxes	$(50,860)	$(177,855)	$(294,564)

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

	Years Ended December 31,		
	2018	2017	2016
	(In thousands)		
Current:			
United States	$122	$10,976	$12,675
Bermuda	—	—	—
Foreign—other	33,864	24,456	102
Total current	33,986	35,432	12,777
Deferred:			
United States	8,514	15,310	(3,594)
Bermuda	—	—	—
Foreign—other	631	(5,805)	(19,967)
Total deferred	9,145	9,505	(23,561)
Income tax expense (benefit)	$43,131	$44,937	$(10,784)

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

	Years Ended December 31,		
	2018	2017	2016
	(In thousands)		
Tax at statutory rate(1)	$(10,681)	$—	$—
Foreign income (loss) taxed at different rates	5,013	9,381	(57,898)
Net non-taxable expense / insurance recoveries	3,256	(30)	8,694
West Leo arbitration settlement	(2,834)	1,736	1,098
Non-deductible compensation	2,643	1,680	1,999
Deferred tax liability - undistributed earnings	(2,565)	2,565	—
Non-deductible and other items	656	3,790	556
Equity earnings - net of tax	(15,305)	—	—
Tax shortfall (windfall) on equity-based compensation, net	(387)	3,086	5,504
Change in valuation allowance	63,335	6,008	29,263
Change in U.S. tax rate	—	16,721	—
Total tax expense (benefit)	$43,131	$44,937	$(10,784)
Effective tax rate(2)	85 %	25 %	4 %

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(1) On December 28, 2018, we changed our jurisdiction of incorporation from Bermuda to the State of Delaware. Kosmos Energy Ltd. discontinued as a Bermuda exempted company pursuant to Section 132G of the Companies Act 1981 of Bermuda and, pursuant to Section 265 of the General Corporation Law of the State of Delaware (the "DGCL"), continued its existence under the DGCL as a corporation organized in the State of Delaware. As a result, the statutory tax rate for the 2018 reconciliation of income tax expense is the U.S. statutory tax rate of 21%. Our 2017 and 2016 reconciliation of income tax expense is based on the Bermuda statutory tax rate of 0%.

(2) The effective tax rate during the years ended December 31, 2018, 2017 and 2016 were impacted by losses of $261.2 million, $164.4 million and $121.4 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 84%, 433% and 179% for the years ended December 31, 2018, 2017 and 2016, respectively. The effective tax rate in the United States is impacted by the effect the sum of non-deductible expenditures and 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.

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The effective tax rate for Ghana is approximately 36%, 49% and 23% for the years ended December 31, 2018, 2017 and 2016, 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,	
	2018	2017
	(In thousands)	
Deferred tax assets:		
Foreign capitalized operating expenses	$128,809	$68,218
Foreign net operating losses	28,050	25,307
United States net operating losses	59,336	—
Equity compensation	11,408	20,783
Unrealized derivative losses	—	33,963
Asset retirement obligation and other	29,450	24,784
Total deferred tax assets	257,053	173,055
Valuation allowance	(156,860)	(93,525)
Total deferred tax assets, net	100,193	79,530
Deferred tax liabilities:		
Depletion, depreciation and amortization related to property and equipment	(547,389)	(533,561)
Unrealized derivative gains	(15,979)	—
Total deferred tax liabilities	(563,368)	(533,561)
Net deferred tax liability	$(463,175)	$(454,031)

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 $103.0 million. Of these losses, we expect $0.9 million, $0.5 million, $0.5 million, $0.6 million, $0.7 million, $15.0 million and $0.1 million to expire in 2019, 2020, 2021, 2022, 2023, 2029 and 2030, respectively, and $84.7 million do not expire. All of these losses currently have offsetting valuation allowances. The Company has $282.5 million of United States net operating loss that will not expire.

The Company will file a 2018 U.S. federal income tax return during 2019. A subsidiary of the Company is open to U.S. federal income tax examinations for tax years 2015 through 2017 and to Texas margin tax examinations for the tax years 2014 through 2017. In addition to the United States, the Company files income tax returns in the countries in which we operate. 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, 2018, 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

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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 shares of common stock or resulted in the issuance of shares of common stock 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 shares of common stock 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,		
	2018	2017	2016
	(In thousands, except per share data)		
Numerator:			
Net loss allocable to common stockholders(1)	$(93,991)	$(222,792)	$(283,780)
Denominator:			
Weighted average number of shares outstanding:			
Basic	404,585	388,375	385,402
Restricted stock awards and units(1)(2)	—	—	—
Diluted	404,585	388,375	385,402
Net loss per share:			
Basic	$(0.23)	$(0.57)	$(0.74)
Diluted	$(0.23)	$(0.57)	$(0.74)

(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 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 share calculation in periods we are in a net loss position. All restricted stock awards were fully vested in January 2018.

(2) For the years ended December 31, 2018, 2017 and 2016, we excluded 10.6 million, 12.9 million and 11.8 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

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redetermination process, our Unit Interest is 24.1%. These consolidated financial statements are based on these redetermined tract participations. Our unit interest may change in the future should another redetermination occur.
The Company leases facilities under various operating leases that fully expire through 2027, including our office space. Rent expense under these agreements, was $4.7 million, $3.3 million and $3.3 million for the years ended December 31, 2018, 2017 and 2016, respectively.
We currently have a commitment to drill one exploration well in Mauritania and Namibia and two exploration wells in Senegal. Our partner is obligated to fund our share of the cost of the exploration wells, subject to the remaining exploration and appraisal carry covering both our Mauritania and Senegal blocks. In Sao Tome and Principe, we have a 3D seismic requirement of approximately 13,500 square kilometers.
Future minimum rental commitments under our leases at December 31, 2018, are as follows:

	Payments Due By Year(1)						
	Total	2019	2020	2021	2022	2023	Thereafter
	(In thousands)						
Operating leases(2)	$36,508	$2,775	$4,173	$3,276	$3,326	$3,376	$ 19,582

(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 office leases.

Performance Obligations

As of December 31, 2018, the Company had secured performance bonds totaling $200.9 million for our supplemental bonding requirements stipulated by the Bureau of Ocean Energy Management ("BOEM") and $3.7 million to another operator related to costs anticipated for the plugging and abandonment of certain wells and the removal of certain facilities in its U.S. Gulf of Mexico fields. As of December 31, 2018, we had $0.6 million of cash collateral against these secured performance bonds which is classified as Other long term assets in our consolidated balance sheet.

In February 2019, Kosmos and BP signed Carry Advance Agreements with the national oil companies of Mauritania and Senegal which obligate us separately to finance the respective national oil company’s share of certain development costs. Kosmos’ total share for the two agreements combined is up to $239.7 million, which is to be repaid through the national oil companies’ share of future revenues.

On February 25, 2019, we announced our quarterly cash dividend of $0.0452 per common share. The dividend is payable on March 28, 2019 to stockholders of record on March 7, 2019.

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16. Additional Financial Information

Accrued Liabilities

Accrued liabilities consisted of the following:

	December 31,	
	2018	2017
	(In thousands)	
Accrued liabilities:		
Exploration, development and production	$92,613	$144,717
Current asset retirement obligations	6,617	—
General and administrative expenses	39,373	31,124
Interest	18,152	20,457
Income taxes	8,958	17,423
Taxes other than income	4,613	3,270
Derivatives	441	—
Revenue payable	24,379	—
Other	450	2,421
	$195,596	$219,412

Gain on sale of assets

During the year ended December 31, 2018, we recognized a $7.7 million gain related to the farm-out of Blocks EG-21, S, and W offshore Equatorial Guinea to Trident.

Other Income, net

Other income, net which includes Loss of Production Income (“LOPI”) payments, consisted of zero, $58.7 million and $74.8 million for the years ended December 31, 2018, 2017 and 2016, respectively. Our LOPI coverage for the turret bearing issue on the Jubilee FPSO ended in May 2017.

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 zero, $17.1 million, and $7.5 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Facilities Insurance Modifications, net

Facilities insurance modifications, net consists of costs associated with the long-term solution to convert the Jubilee FPSO to a permanently spread moored facility, net of any insurance reimbursements.

Other Expenses, net

Other expenses, net incurred during the period is comprised of the following:

	Years Ended December 31,		
	2018	2017	2016
	(In thousands)		
Loss on disposal of inventory	$280	$866	$14,900
Gain on insurance settlements	—	(461)	(4,003)
Disputed charges and related costs, net of recoveries	(9,753)	4,962	11,299
Other, net	2,972	(76)	920
Other expenses, net	$(6,501)	$5,291	$23,116

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 charged such

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expenditures to the Deepwater Tano ("DT") joint account. Kosmos disputed through arbitration that these expenditures were 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. In July 2018, the International Chamber of Commerce ("ICC") issued its Final Award in the arbitration in favor of Kosmos. As a result, we recovered from Tullow Ghana Limited disputed charges in the amount of $12.9 million in the form of cash payments and offsets against other unrelated joint venture costs, which include amounts previously paid under protest as well as certain costs and fees incurred pursuing the arbitration.

17. Business Segment Information

Kosmos is engaged in a single line of business, which is the exploration and development of oil and gas.

At December 31, 2018, the Company had operations in four geographic reporting segments: Ghana, Equatorial Guinea, Mauritania/Senegal and the United States. To assess performance of the reporting segments, the Chief Operating Decision Maker ("CODM") reviews capital expenditures. Capital expenditures, as defined by the Company, may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with our consolidated financial statements and notes thereto. Financial information for each area is presented below:

	Ghana	Equatorial Guinea(1)	Mauritania/Senegal	United States(2)	Corporate & Other	Eliminations(3)	Total
	(in thousands)						
Year ended December 31, 2018							
Revenues and other income:							
Oil and gas revenue	$739,070	$360,649	$ —	$147,596	$—	$(360,649)	$886,666
Gain on sale of assets	—	7,666	—	—	—	—	7,666
Other income, net	(17)	(238)	—	11	150,635	(142,354)	8,037
Total revenues and other income	739,053	368,077	—	147,607	150,635	(503,003)	902,369
Costs and expenses:							
Oil and gas production	189,104	73,843	—	30,470	5,153	(73,843)	224,727
Facilities insurance modifications, net	6,955	—	—	—	—	—	6,955
Exploration expenses	58,276	38,164	7,262	66,962	131,180	(352)	301,492
General and administrative	19,342	5,351	5,220	10,534	168,542	(109,133)	99,856
Depletion and depreciation	265,805	134,983	61	59,835	4,134	(134,983)	329,835
Interest and other financing costs, net(4)	86,738	(12)	(25,386)	7,487	39,483	(7,134)	101,176
Derivatives, net	—	—	—	(57,615)	26,185	—	(31,430)
(Gain) loss on equity method investments, net	—	—	—	—	—	(72,881)	(72,881)
Other expenses, net	16,414	(814)	(23)	598	3,510	(26,186)	(6,501)
	642,634	251,515	(12,866)	118,271	378,187	(424,512)	953,229

Total costs and expenses							
Loss before income taxes	96,419	116,562	12,866	29,336	(227,552)	(78,491)	(50,860)
Income tax expense (benefit)	34,494	78,491	—	6,163	2,474	(78,491)	43,131
Net loss	$61,925	$38,071	$ 12,866	$23,173	$(230,026)	$—	$(93,991)
Consolidated capital expenditures	$105,942	$32,156	$ 11,962	$95,993	$139,381	$—	$385,434
As of December 31, 2018							
Property and equipment, net	$1,698,194	$3,919	$ 411,448	$1,308,670	$37,470	$—	$3,459,701
Total assets	$1,930,071	$55,302	$ 536,620	$3,512,989	$10,349,488	$(12,296,281)	$4,088,189

(1) Includes our proportionate share of our equity method investment in KTIPI, including our basis difference which is reflected in depletion and depreciation for the year ended December 31, 2018, except for capital expenditures. See Note 7 - Equity Method Investments for additional information regarding our equity method investments.

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(2) Represents activity commencing September 14, 2018, the DGE acquisition date.

(3) Includes elimination of proportionate consolidation amounts recorded for KTIPI to reconcile to (Gain) loss on equity method investments, net as reported in the consolidated statements of operations.

(4) Interest expense is recorded based on actual third-party and intercompany debt agreements. Capitalized interest is recorded on the business unit where the assets reside.

	Ghana	Equatorial Guinea(1)	Mauritania/Senegal	United States	Corporate & Other	Eliminations(2)	Total
	(in thousands)						
Year ended December 31, 2017							
Revenues and other income:							
Oil and gas revenue	$578,139	$27,308	$ —	$ —	$—	$(27,308)	$578,139
Gain on sale of assets	—	—	—	—	—	—	—
Other income, net	5	147	—	—	$219,968	(161,423)	58,697
Total revenues and other income	578,144	27,455	—	—	219,968	(188,731)	636,836
Costs and expenses:							
Oil and gas production	137,584	7,755	—	—	(10,734)	(7,755)	126,850
Facilities insurance modifications, net	(820)	—	—	—	—	—	(820)
Exploration expenses	394	86	71,456	—	144,114	—	216,050
General and administrative	14,836	672	8,298	—	138,661	(94,165)	68,302
Depletion and depreciation	251,890	11,181	20	—	3,293	(11,181)	255,203
Interest and other financing costs, net(3)	71,592	—	(16,065)	—	29,202	(7,134)	77,595
Derivatives, net	—	—	—	—	59,968	—	59,968
Loss on equity method investments, net	—	—	11,486	—	—	(5,234)	6,252
Other expenses, net	64,768	—	867	—	(376)	(59,968)	5,291
Total costs and expenses	540,244	19,694	76,062	—	364,128	(185,437)	814,691
Income (loss) before income taxes	37,900	7,761	(76,062)	—	(144,160)	(3,294)	(177,855)
Income tax expense (benefit)	18,649	3,294	3	—	26,285	(3,294)	44,937
Net income (loss)	$19,251	$4,467	$ (76,065)	$ —	$(170,445)	$—	$(222,792)
Consolidated capital expenditures	$5,545	$1,995	$ (80,929)	$ —	$130,821	$—	$57,432
As of December 31, 2017							
Property and equipment, net	$1,901,127	$1,908	$ 381,422	$ —	$33,371	$—	$2,317,828
Total assets	$2,263,824	$237,835	$ 570,044	$ —	$8,671,437	$(8,550,537)	$3,192,603

(1) Includes our proportionate share of our equity method investment in KTIPI, including our basis difference which is reflected in depletion and depreciation for the year ended December 31, 2017, except for capital expenditures. See Note 7 - Equity Method Investments for additional information regarding our equity method investments.

(2) Includes elimination of proportionate consolidation amounts recorded for KTIPI to reconcile to (Gain) loss on equity method investments, net as reported in the consolidated statements of operations.

(3) Interest expense is recorded based on actual third-party and intercompany debt agreements. Capitalized interest is recorded on the business unit where the assets reside.

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	Ghana	Equatorial Guinea	Mauritania/Senegal	United States	Corporate & Other	Eliminations	Total
	(in thousands)						
Year ended December 31, 2016							
Revenues and other income:							
Oil and gas revenue	$310,377	$ —	$ —	$ —	$—	$—	$310,377
Gain on sale of assets	—	—	—	—	—	—	—
Other income, net	7	—	—	—	$227,101	(152,130)	74,978
Total revenues and other income	310,384	—	—	—	227,101	(152,130)	385,355
Costs and expenses:							
Oil and gas production	121,329	—	—	—	(1,962)	—	119,367
Facilities insurance modifications, net	14,961	—	—	—	—	—	14,961
Exploration expenses	1,211	9	63,186	—	137,874	—	202,280
General and administrative	9,490	—	21,530	—	153,577	(96,974)	87,623
Depletion and depreciation	137,094	—	97	—	3,213	—	140,404
Interest and other financing costs, net(1)	45,403	—	(22,404)	—	28,282	(7,134)	44,147
Derivatives, net	—	—	—	—	48,021	—	48,021
Loss on equity method investments, net	—	—	—	—	—	—	—
Other expenses, net	67,793	—	454	—	2,890	(48,021)	23,116
Total costs and expenses	397,281	9	62,863	—	371,895	(152,129)	679,919
Income (loss) before income taxes	(86,897)	(9)	(62,863)	—	(144,794)	(1)	(294,564)
Income tax expense (benefit)	(19,866)	—	—	—	9,082	—	(10,784)
Net income (loss)	$(67,031)	$ (9)	$ (62,863)	$ —	$(153,876)	$(1)	$(283,780)
Consolidated capital expenditures	$221,294	$ 9	$ 283,442	$ —	$139,765	$—	$644,510
As of December 31, 2016							
Property and equipment, net	$2,129,873	$ —	$ 529,071	$ —	$49,948	$—	$2,708,892
Total assets	$2,484,497	$ (3)	$ 551,250	$ —	$8,205,043	$(7,899,322)	$3,341,465

(1) Interest expense is recorded based on actual third-party and intercompany debt agreements. Capitalized interest is recorded on the business unit where the assets reside.

	Years Ended December 31,		
	2018	2017	2016
	(In thousands)		
Consolidated capital expenditures:			
Consolidated Statements of Cash Flows - Investing activities:			
Oil and gas assets	$213,806	$140,495	$535,975
Other property	7,935	2,858	1,998
Adjustments:			
Changes in capital accruals	26,669	(6,337)	(26,725)
Exploration expense, excluding unsuccessful well costs(1)	178,293	172,849	199,806

Capitalized interest	(28,331)	(30,282)	(59,803)
Proceeds on sale of assets	(13,703)	(222,068)	(210)
Other	765	(83)	(6,531)
Total consolidated capital expenditures	$385,434	$57,432	$644,510

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(1) Unsuccessful well costs are included in oil and gas assets when incurred.

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, 2018, 2017 and 2016. 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, the U.S. Gulf of Mexico (commencing September 14, 2018, the DGE acquisition date), and our equity method investment offshore Equatorial Guinea.

	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, 2015(1)	74	14	76	—	—	—	76
Production	(7)	(1)	(7)	—	—	—	(7)
Revision in estimate(2)	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(3)	18	35	24	—	—	—	24
Purchases of minerals-in-place(4)	—	—	—	20	13	21	21
Net proved developed and undeveloped reserves at December 31, 2017(1)	82	49	89	19	13	21	110
Extensions and discoveries	—	—	—	—	—	—	—
Production	(13)	(3)	(14)	(5)	—	(5)	(19)
Revision in estimate(5)	11	(1)	11	10	1	10	21
Purchases of minerals-in-place(6)	47	40	54	—	—	—	54
Net proved developed and undeveloped reserves at December 31, 2018(1)	127	85	141	24	14	26	167
Proved developed reserves(1)							
December 31, 2016	64	13	66	—	—	—	66
December 31, 2017	59	38	65	18	13	20	85
December 31, 2018	81	57	91	23	14	25	116
Proved undeveloped reserves(1)							
December 31, 2016	10	2	11	—	—	—	11
December 31, 2017	23	11	24	1	—	1	25
December 31, 2018	45	28	50	1	—	1	51

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(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) 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.
(3) 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.
(4) The increase in purchase of minerals in place is related to Equatorial Guinea, representing the reserves associated with our equity method investment.
(5) The increase in proved reserves is a result of a 10 MMBoe increase in Jubilee related to strong field performance, positive drilling results and increased estimate of original oil in place. Changes at TEN include a positive revision of 4 MMBbl due to increased estimate of original oil in place, new drilling and development plan updates, and a negative revision of 3 MMBbl due to recovery factor adjustment from dynamic modeling. Changes at Equatorial Guinea are primarily a 4 MMBbl positive revision due to strong field performance at both Ceiba and Okume Complex and a 6 MMBbl positive revision due to reservoir management strategies (re-opening shut-in wells, stimulations, surface/subsurface equipment installation).
(6) The increase in purchase of minerals in place is related to the DGE acquisition completed in September 2018.

Net proved reserves were calculated utilizing the twelve month unweighted arithmetic average of the first day of the month oil price for each month based on the respective benchmark price in the period January through December 2018. The average price is adjusted for crude handling, transportation fees, quality, and a regional price differential.

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	U.S. Gulf of Mexico	Other(1)	Kosmos Total	Equity Method Investment-Equatorial Guinea(2)	Total
	(In thousands)					
As of December 31, 2018						
Unproved properties	$—	$318,831	$440,641	$759,472	$ —	$759,472
Proved properties	3,191,157	1,045,332	—	4,236,489	2,850,316	7,086,805
	3,191,157	1,364,163	440,641	4,995,961	2,850,316	7,846,277
Accumulated depletion	(1,493,111)	(57,986)	—	(1,551,097)	(2,717,020)	(4,268,117)
Net capitalized costs	$1,698,046	$1,306,177	$440,641	$3,444,864	$ 133,296	$3,578,160
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

(1) Includes Africa (excluding Ghana) and South America.

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(2) Represents 50% interest in KTIPI's capitalized costs related to oil and gas activities.
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	U.S. Gulf of Mexico	Other(1)	Kosmos Total	Equity Method Investment-Equatorial Guinea(2)	Total
	(In thousands)					
Year ended December 31, 2018						
Property acquisition:						
Unproved	$—	$302,688	$2,975	$305,663	$ —	$305,663
Proved	—	1,037,511	—	1,037,511	—	1,037,511
Exploration	3,182	69,673	199,423	272,278	—	272,278
Development	110,401	21,252	4,569	136,222	—	136,222
Total costs incurred	$113,583	$1,431,124	$206,967	$1,751,674	$ —	$1,751,674
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		

(1) Includes Africa (excluding Ghana), Europe and South America.
(2) For year ended December 31, 2017, 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.

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 2018. The average price is adjusted for crude handling, transportation fees, quality, and a regional price differential.
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 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.

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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	U.S. Gulf of Mexico	Equity Method Investment-Equatorial Guinea	Total
	(In millions)			
At December 31, 2018				
Future cash inflows	$5,882	$2,951	$ 1,735	$10,568
Future production costs	(1,613)	(338)	(583)	(2,534)
Future development costs	(928)	(467)	(378)	(1,773)
Future tax expenses	(1,052)	(379)	(416)	(1,847)
Future net cash flows	2,289	1,767	358	4,414
10% annual discount for estimated timing of cash flows	(749)	(397)	33	(1,113)
Standardized measure of discounted future net cash flows	$1,540	$1,370	$ 391	$3,301
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			

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(1) The Company was a tax exempt company incorporated pursuant to the laws of Bermuda at December 31, 2017 and 2016. The Company was not 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 and 2016, respectively, only reflect the effects of future tax expense levied at an asset level.

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Changes in the Standardized Measure for Discounted Cash Flows

	Ghana	U.S. Gulf of Mexico	Equity Method Investment-Equatorial Guinea	Total
	(In millions)			
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	—	—	
Changes in timing and other	(53)	—	—	
Balance at December 31, 2017	$971	$—	$ 130	$1,101
Purchase of minerals in place	—	1,487	—	1,487
Sales and transfers 2018	(545)	(117)	(287)	(949)
Extensions and discoveries	—	—	—	—
Net changes in prices and costs	1,154	—	408	1,562
Previously estimated development costs incurred during the period	105	—	—	105
Net changes in development costs	181	—	29	210
Revisions of previous quantity estimates	485	—	574	1,059
Net changes in tax expenses	(565)	—	(136)	(701)
Accretion of discount	112	—	30	142
Changes in timing and other	(358)	—	(357)	(715)
Balance at December 31, 2018	$1,540	$1,370	$ 391	$3,301

(1) The Company was a tax exempt company incorporated pursuant to the laws of Bermuda at December 31, 2017 and 2016. The Company was not 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 and 2016, respectively, only reflect the effects of future tax expense levied at an asset level.

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KOSMOS ENERGY LTD.
Supplemental Quarterly Financial Information (Unaudited)

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
	(In thousands, except per share data)			
2018				
Revenues and other income	$127,177	$215,473	$ 250,219	$ 309,500
Costs and expenses	201,751	364,091	364,912	22,475
Net income (loss)	(50,226)	(103,273)	(126,057)	185,565
Net income (loss) per share:				
Basic(1)	(0.13)	(0.26)	(0.31)	0.44
Diluted(1)	(0.13)	(0.26)	(0.31)	0.43
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)

(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.

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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, 2018, 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.
On September 14, 2018, we completed the acquisition of Deep Gulf Energy (together with its subsidiaries "DGE"). We are in the process of integrating operations of DGE and affiliated entities related to this acquired business (“DGE business”), including internal controls over financial reporting and, therefore, management's evaluation and conclusion as to the effectiveness of our internal control over financial reporting as of the end of the period covered by this Annual Report on Form 10-K excludes any evaluation of the internal control over financial reporting of the DGE business. The DGE business accounted for 37% of the Company's total assets and 17% of total revenues of the Company as of and for the year ended December 31, 2018.

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, 2018 which is included in "Item 8. Financial Statements and Supplementary Data."

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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 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, 2018. 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, 2018, as the case may be, additional reportable transactions may be disclosed by such companies.

As of December 31, 2018, funds affiliated with Warburg Pincus (“Warburg Pincus”) held approximately 8% of our outstanding common shares. We were also a party to a shareholders agreement with Warburg Pincus pursuant to which, among other things, Warburg Pincus had the right until November 28, 2018 to designate two members of our board of directors. Accordingly, Warburg Pincus was deemed an “affiliate” of us, during the fiscal quarter ended December 31, 2018.

Disclosure relating to Warburg Pincus and its affiliates

Warburg Pincus informed us of (i) the information reproduced below (the “EIGI Disclosure”) regarding Endurance International Group Holdings, Inc. (together with its subsidiaries, "EIGI"). EIGI is a company that may be considered an affiliate of Warburg Pincus. Because we and EIGI may be deemed to be controlled by Warburg Pincus, we may be considered an “affiliate” of each of EIGI for the purposes of Section 13(r) of the Exchange Act.

EIGI Disclosure:

Quarter ended December 31, 2018

“On July 25, 2018, the Office of Foreign Assets Control (“OFAC”) designated Electronics Katrangi Trading (“Katrangi”) as a Specially Designated National (“SDN”) pursuant to the Weapons of Mass Destruction Proliferators Sanctions Regulations, 31 C.F.R. Part 544. On July 30, 2018, during a regular compliance scan of EIGI’s user base, EIGI identified the domain SGP-FRANCE.COM (the “Domain Name”) which was listed as a website associated with Katrangi, on one of EIGI’s platforms. The Domain Name was managed using one of EIGI’s platforms by one of its reseller customers. Accordingly, there was no direct financial transaction between EIGI and the registered owner of the Domain Name and EIGI did not generate any revenue in connection with the Domain Name since Katrangi was added to the SDN list on July 25, 2018. Upon discovering the Domain Name on its platform, EIGI promptly suspended the Domain Name and removed it from its platform. EIGI reported the Domain Name to OFAC on August 7, 2018."

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the 2019 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2018.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2019 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2018.

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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 2019 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2018.
Item 13. Certain Relationships and Related Transactions, and Director Independence
The information required by this item is incorporated herein by reference to the 2019 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2018.
Item 14. Principal Accounting Fees and Services
The information required by this item is incorporated herein by reference to the 2019 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2018.
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 2018, 2017 and 2016 (collectively "KEL," the "Parent Company"), such subsidiaries may be 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.

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KOSMOS ENERGY LTD.
CONDENSED PARENT COMPANY BALANCE SHEETS
(In thousands, except share data)

	December 31, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$6,776	$297
Receivables from subsidiaries	2,890	—
Note receivable from subsidiary	7,941	—
Prepaid expenses and other	313	290
Total current assets	17,920	587
Investment in subsidiaries at equity	1,432,468	1,419,890
Long-term note receivable from subsidiary	607,943	—
Deferred financing costs, net of accumulated amortization of $12,065 and $13,951 at December 31, 2018 and December 31, 2017, respectively	8,937	2,510
Restricted cash	305	—
Long-term deferred tax asset	(1,132)	—
Total assets	$2,066,441	$1,422,987
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable	$975	$4
Accounts payable to subsidiaries	—	332
Accrued liabilities	18,972	19,128
Total current liabilities	19,947	19,464
Long-term debt	836,016	506,411
Long-term note payable to subsidiary	269,000	—
Shareholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2018 and December 31, 2017	—	—
Common stock, $0.01 par value; 2,000,000,000 authorized shares; 442,914,675 and 398,599,457 issued at December 31, 2018 and December 31, 2017, respectively	4,429	3,986
Additional paid-in capital	2,341,249	2,014,525
Accumulated deficit	(1,167,193)	(1,073,202)
Treasury stock, at cost, 44,263,269 and 9,188,819 shares at December 31, 2018 and December 31, 2017, respectively	(237,007)	(48,197)
Total shareholders' equity	941,478	897,112
Total liabilities and shareholders' equity	$2,066,441	$1,422,987

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KOSMOS ENERGY LTD.
CONDENSED PARENT COMPANY STATEMENTS OF OPERATIONS
(In thousands)

	Years Ended December 31,		
	2018	2017	2016
Revenues and other income:			
Oil and gas revenue	$—	$—	$—
Total revenues and other income	—	—	—
Costs and expenses:			
General and administrative	47,279	51,544	48,542
General and administrative recoveries—related party	(36,197)	(40,266)	(40,047)
Interest and other financing costs, net	66,055	55,596	55,253
Interest and other financing costs, net—related party	(7,941)	—	—
Other expenses, net	49	40	1
Equity in losses of subsidiaries	23,614	155,878	220,031
Total costs and expenses	92,859	222,792	283,780
Loss before income taxes	(92,859)	(222,792)	(283,780)
Income tax expense	1,132	—	—
Net loss	$(93,991)	$(222,792)	$(283,780)

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KOSMOS ENERGY LTD.
CONDENSED PARENT COMPANY STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31,		
	2018	2017	2016
Operating activities			
Net loss	$(93,991)	$(222,792)	$(283,780)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Equity in losses of subsidiaries	23,614	155,878	220,031
Equity-based compensation	35,230	39,913	40,423
Amortization	7,292	3,070	3,070
Deferred income taxes	1,132	—	—
Other	268	3,884	3,530
Changes in assets and liabilities:			
Decrease in receivables	1,234	986	—
(Increase) decrease in prepaid expenses and other	(23)	127	52
(Increase) decrease due to/from related party	(42,163)	14,463	(15,201)
Increase in accounts payable and accrued liabilities	816	1,179	312
Net cash provided by (used in) operating activities	(66,591)	(3,292)	(31,563)
Investing activities			
Investment in subsidiaries	(36,192)	4,691	(40,047)
Net cash provided by (used in) investing activities	(36,192)	4,691	(40,047)
Financing activities			
Borrowings under long-term debt	400,000	—	—
Payments on long-term debt	(75,000)		
Purchase of treasury stock	(206,051)	(2,194)	(1,981)
Deferred financing costs	(9,382)	—	—
Net cash provided by (used in) financing activities	109,567	(2,194)	(1,981)
Net increase (decrease) in cash and cash equivalents	6,784	(795)	(73,591)
Cash, cash equivalents and restricted cash at beginning of period	297	1,092	74,683
Cash, cash equivalents and restricted cash at end of period	$7,081	$297	$1,092
Non-cash activity:			
Issuance of common stock for related party receivable	$307,944	$—	$—

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Schedule II
Kosmos Energy Ltd.
Valuation and Qualifying Accounts
For the Years Ended December 31, 2018, 2017 and 2016

Description	Balance January 1,	Additions Charged to Costs and Expenses	Charged To Other Accounts	Deductions From Reserves	Balance December 31,
2018					
Allowance for doubtful receivables	$ —	$ 1,211	$ —	$ —	$ 1,211
Allowance for deferred tax assets	$ 93,525	$ 63,335	$ —	$ —	$ 156,860
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

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 139 for a description of the exhibits filed as part of this report.

Item 16. Form 10-K Summary

None

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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 28, 2019 By: /s/ Thomas P. Chambers
Thomas P. Chambers
Senior Vice President and Chief Financial Officer

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 28, 2019
/s/ Thomas P. Chambers Thomas P. Chambers	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2019
/s/ Paul M. Nobel Paul M. Nobel	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 28, 2019
/s/ Brian F. Maxted Brian F. Maxted	Director	February 28, 2019
/s/ Sir Richard B. Dearlove Sir Richard B. Dearlove	Director	February 28, 2019
/s/ Deanna L. Goodwin Deanna L. Goodwin	Director	February 28, 2019
/s/ Adebayo O. Ogunlesi Adebayo O. Ogunlesi	Director	February 28, 2019
/s/ Chris Tong Chris Tong	Director	February 28, 2019

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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 Form 8-K12g-3 filed December 28, 2018 (File No. 000 56014), and incorporated herein by reference).
3.2	Bylaws of the Company (filed as Exhibit 3.2 to the Company's Form 8-K12g-3 filed December 31, 2018 (File No. 000 56014), and incorporated herein by reference).
4.1	Form of Common Stock Certificate (filed as Exhibit 4.1 to the Company's Form 8 K12g-3 filed December 28, 2018 (File No. 000 56014), and incorporated herein by reference).
	Operating Agreements
	Certain of the agreements listed below have been filed pursuant to the Company's voluntary compliance with international transparency standards and are not material contracts as such term is used in Item 601(b)(10) of Regulation S-K.
	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	Joint 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	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).
10.6	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).
	Sao Tome and Principe
10.7	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).
10.8	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).
10.9	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).

10.10	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).
10.11	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).

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Exhibit Number	Description of Document
10.12	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).
10.13	Production Sharing Contract relating to Block 10 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe, BP Exploration (STP) Limited and Kosmos Energy Sao Tome and Principe dated March 9, 2018 (filed as Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.14	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).
10.15	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).
10.16	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).
10.17	Production Sharing Contract relating to Block 13 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe, BP Exploration (STP) Limited and Kosmos Energy Sao Tome and Principe dated March 9, 2018 (filed as Exhibit 10.9 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
	Senegal
10.18	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).
10.19	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).
10.20	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
10.21	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).
10.22	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).
	Mauritania

10.23	Exploration and Production Contract between The Islamic Republic of Mauritania and Kosmos Energy Mauritania (Bloc 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).
10.24	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).
10.25	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).
10.26	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).

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Exhibit Number	Description of Document
10.27	Exploration and Production Contract between The Islamic Republic of Mauritania and Tullow Mauritania Limited (Bloc C18) dated May 17, 2012 (filed as Exhibit 10.42 to the Company's Annual Report on Form 10-K of the year ended December 31, 2017, and incorporated herein by reference).
	Equatorial Guinea
10.28	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 (filed as Exhibit 10.43 to the Company's Annual Report on Form 10-K of the year ended December 31, 2017, and incorporated herein by reference).
10.29	Production Sharing Contract relating to Block G Offshore Republic of Equatorial Guinea between the Republic of Equatorial Guinea and Triton Equatorial Guinea, Inc. dated March 26, 1997 (filed as Exhibit 10.1 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.30	Amendment No. 1, dated January 1, 2000, to the Production Sharing Contract relating to Block G Offshore Republic of Equatorial Guinea between Triton Equatorial Guinea, Inc., Energy Africa Equatorial Guinea Limited, and the Republic of Equatorial Guinea represented by the Ministry of Mines and Energy (filed as Exhibit 10.2 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.31	Amendment No. 2, dated December 15, 2005, to the Production Sharing Contract relating to Block G Offshore Republic of Equatorial Guinea between Amerada Hess Equatorial Guinea, Energy Africa Equatorial Guinea Limited, and the Republic of Equatorial Guinea represented by the Ministry of Mines, Industry and Energy (filed as Exhibit 10.3 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.32	Amendment No. 3, dated October 22, 2017, to the Production Sharing Contract relating to Block G Offshore Republic of Equatorial Guinea between Hess Equatorial Guinea, Tullow Equatorial Guinea Limited, and the Republic of Equatorial Guinea represented by the Ministry of Mines and Hydrocarbons (filed as Exhibit10.4 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.33	Production Sharing Contract relating to Block EG-21 Offshore Republic of Equatorial Guinea between the Republic of Equatorial Guinea, Guinea Ecuatorial de Petroleos and Kosmos Energy Equatorial Guinea dated October 10, 2017 (filed as Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.34	Production Sharing Contract relating to Block S Offshore Republic of Equatorial Guinea between the Republic of Equatorial Guinea, Guinea Ecuatorial de Petroleos and Kosmos Energy Equatorial Guinea dated October 10, 2017 (filed as Exhibit 10.6 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.35	Production Sharing Contract relating to Block W Offshore Republic of Equatorial Guinea between the Republic of Equatorial Guinea, Guinea Ecuatorial de Petroleos and Kosmos Energy Equatorial Guinea dated October 10, 2017 (filed as Exhibit 10.7 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.36	Production Sharing Contract relating to Block EG-24 Offshore Equatorial Guinea between the Republic of Equatorial Guinea, Guinea Ecuatorial de Petroleos and Ophir Equatorial Guinea (EG-24) Limited dated October 2017 (filed as Exhibit 10.1 to the Company’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, and incorporated herein by reference).
	Cote d'Ivoire
10.37	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 (filed

	as Exhibit 10.44 to the Company's Annual Report on Form 10-K of the year ended December 31, 2017, and incorporated herein by reference).
10.38	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 (filed as Exhibit 10.45 to the Company's Annual Report on Form 10-K of the year ended December 31, 2017, and incorporated herein by reference).
10.39	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 (filed as Exhibit 10.46 to the Company's Annual Report on Form 10-K of the year ended December 31, 2017, and incorporated herein by reference).

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Exhibit Number	Description of Document
10.40	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 (filed as Exhibit 10.47 to the Company's Annual Report on Form 10-K of the year ended December 31, 2017, and incorporated herein by reference).
10.41	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 (filed as Exhibit 10.48 to the Company's Annual Report on Form 10-K of the year ended December 31, 2017, and incorporated herein by reference).
	Namibia
10.42*	Petroleum Agreement between the Government of the Republic of Namibia and Signet Petroleum Limited Cricket Investments (PTY) LTD National Petroleum Corporation of Namibia (Block 2914B) dated June 2011.
10.43*	Addendum to Petroleum Agreement between The Government of the Republic of Namibia and Shell Namibia Upstream B.V. and National Petroleum Corporation of Namibia dated June 17, 2011.
10.44*	Addendum II to Petroleum Agreement between The Government of the Republic of Namibia and Shell Namibia Upstream B.V. and National Petroleum Corporation of Namibia dated June 17, 2011.
	Financing Agreements
10.45	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).
10.46	Deed of Amendment and Restatement relating to the Facility Agreement, dated February 5, 2018 among Kosmos Energy Finance International, Kosmos Energy Operating, Kosmos Energy International, Kosmos Energy Development, Kosmos Energy Ghana HC, Kosmos Energy Senegal, Kosmos Energy Mauritania, Kosmos Energy Equatorial Guinea, Kosmos Energy Investments Senegal Limited, BNP Paribas and Standard Chartered Bank (filed as Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.47	Amended and Restated Revolving Credit Facility Agreement, dated August 6, 2018, among Kosmos Energy Ltd., as Original Borrower, certain of its subsidiaries listed therein, as Guarantors, ING Bank N.V., as Facility Agent, Crédit Agricole Corporate and Investment Bank, as Security and Intercreditor Agent, and the financial institutions listed therein, as Lenders (filed as Exhibit 1.1 to the Company's Current Report on Form 8-K filed August 7, 2018 (File No. 001-35167), and incorporated herein by reference).
10.48	Share Repurchase Agreement dated November 25, 2018 (filed as Exhibit 1.2 to the Company's Current Report on Form 8-K filed November 26, 2018 (File No. 001-35167), and incorporated herein by reference).
	Agreements with Shareholders and Directors
10.49	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).
10.50	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) (the "Shareholders Agreement").
10.51	Waiver Letter of funds affiliated with The Blackstone Group L.P., dated November 28, 2018 regarding the Shareholders Agreement (filed as Exhibit 1.1 to the Company's Current Report on Form 8-K filed November 30, 2018 (File No. 001-35167), and incorporated herein by reference).
10.52	Waiver Letter of funds affiliated with Warburg Pincus LLC, dated November 28, 2018 regarding the Shareholders Agreement (filed as Exhibit 1.2 to the Company's Current Report on Form 8-K filed November 30, 2018 (File No. 001-35167), and incorporated herein by reference).

10.53	Amended and Restated 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).
10.54	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).
10.55	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).

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Exhibit Number	Description of Document
	Management Contracts/Compensatory Plans or Arrangements
10.56†	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).
10.57†	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).
10.58†	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).
10.59†	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).
10.60†	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).
10.61†	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).
10.62†	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).
10.63†	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).
10.64†	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).
10.65†	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).
10.66†	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).
10.67†	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).
10.68†	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).
10.69†	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).
10.70†	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).
10.71†	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).
	DGE Acquisition
10.72	Securities Purchase Agreement by and among DGE Group Series Holdco, LLC, and each of its three designated series, DGE Group Series Holdco, LLC, Series I, DGE Group Series Holdco, LLC, Series, II, DGE Group Series Holdco, LLC, Series III, and Kosmos Energy Gulf of Mexico, LLC dated August 3, 2018 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed November 5, 2018 (File No. 001-35167),

	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.

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Exhibit Number	Description of Document
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.