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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2020

☐ **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	Trading Symbol	Name of each exchange on which registered:
Common Stock $0.01 par value	KOS	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 ☒ No ☐

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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 (Do not check if a smaller reporting company)	☐	Smaller reporting company	☐
		Emerging growth company	☐

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

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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

The aggregate market value of the voting and non-voting common 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 $659,507,173.

The number of the registrant's Common Stock outstanding as of February 15, 2021 was 407,843,523.

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, 2020.

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, 2018 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.

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.
"ANP-STP"	Agencia Nacional Do Petroleo De Sao Tome E Principe.
"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.
"Asset Coverage Ratio"	The "Asset Coverage Ratio" as defined in the GoM Term Loan means, as of each March 31, June 30, September 30 and December 31 of each Fiscal Year, commencing December 31, 2020, the ratio of (a) Total PDP PV-10 (as defined in the GoM Term Loan) as of such date to (b) outstanding principal amount of Loans (as defined in the GoM Term Loan) as of such date.
"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.
"BOEM"	Bureau of Ocean Energy Management.
"Boepd"	Barrels of oil equivalent per day.
"Bopd"	Barrels of oil per day.
"BP"	BP p.l.c. and related subsidiaries
"Bwpd"	Barrels of water per day.
"Corporate Revolver"	Revolving Credit Facility Agreement dated November 23, 2012 (as amended or as amended and restated from time to time).
"COVID-19"	Coronavirus disease 2019.
"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.
"DGE"	Deep Gulf Energy (together with its subsidiaries).
"DST"	Drill stem test.
"Dry hole" or "Unsuccessful well"	A well that has not encountered a hydrocarbon bearing reservoir expected to produce in commercial quantities.
"DT"	Deepwater Tano.

“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 for the period it was an equity method investment and includes Last Twelve Months ("LTM") EBITDAX for any acquisitions and excludes LTM EBITDAX for any divestitures.
"ESG"	Environmental, social, and governance.
"ESP"	Electric submersible pump.
“E&P”	Exploration and production.
"Facility"	Facility agreement dated March 28, 2011 (as amended or as amended and restated from time to time).
“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.
"FEED"	Front End Engineering Design.
“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 liquefied natural gas.
“FPS”	Floating production system.
“FPSO”	Floating production, storage and offloading vessel.
"GAAP"	Generally Accepted Accounting Principles in the United States of America.
"GEPetrol"	Guinea Equatorial De Petroleos.
"GHG"	Greenhouse gas.
"GJFFDP"	Greater Jubilee Full Field Development Plan.
"GNPC"	Ghana National Petroleum Corporation.
"GoM Term Loan"	Senior Secured Term Loan Credit Agreement dated September 30, 2020.
“Greater Tortue Ahmeyim”	Ahmeyim and Guembeul discoveries.
"GTA UUOA"	Unitization and Unit Operating Agreement covering the Greater Tortue Ahmeyim Unit.
"HLS"	Heavy Louisiana Sweet.
"H&M"	Hull and Machinery insurance.
"Jubilee UUOA"	Unitization and Unit Operating Agreement covering the Jubilee Unit.
"KTEGI"	Kosmos-Trident Equatorial Guinea Inc.
"KTIPI"	Kosmos-Trident International Petroleum Inc.
“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.
"LNG"	Liquefied natural gas.

"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.
"LSE"	London Stock Exchange.
"LTIP"	Long Term Incentive Plan.
"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.
"MMTPA"	Million metric tonnes per annum.
"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.
"NYSE"	New York Stock Exchange.
"Ophir"	Ophir Energy plc.
"Petroleum contract"	A contract in which the owner of hydrocarbons gives an E&P company temporary and limited rights, including an exclusive option to explore for, develop, and produce hydrocarbons from the lease area.
"Petroleum system"	A petroleum system consists of organic material that has been buried at a sufficient depth to allow adequate temperature and pressure to expel hydrocarbons and cause the movement of oil and natural gas from the area in which it was formed to a reservoir rock where it can accumulate.
"Plan of development" or "PoD"	A written document outlining the steps to be undertaken to develop a field.
"Productive well"	An exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.
"Prospect(s)"	A potential trap that may contain hydrocarbons and is supported by the necessary amount and quality of geologic and geophysical data to indicate a probability of oil and/or natural gas accumulation ready to be drilled. The five required elements (generation, migration, reservoir, seal and trap) must be present for a prospect to work and if any of these fail neither oil nor natural gas may be present, at least not in commercial volumes.
"Proved reserves"	Estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be economically recoverable in future years from known reservoirs under existing economic and operating conditions, as well as additional reserves expected to be obtained through confirmed improved recovery techniques, as defined in SEC Regulation S-X 4-10(a)(2).
"Proved developed reserves"	Those proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.
"Proved undeveloped reserves"	Those proved reserves that are expected to be recovered from future wells and facilities, including future improved recovery projects which are anticipated with a high degree of certainty in reservoirs which have previously shown favorable response to improved recovery projects.
"RSC"	Ryder Scott Company, L.P.
"SEC"	Securities and Exchange Commission.
"Senior Notes"	7.125% Senior Notes due 2026.
"Senior Secured Notes"	7.875% Senior Secured Notes due 2021.
"Shelf margin"	The path created by the change in direction of the shoreline in reaction to the filling of a sedimentary basin.
"Shell"	Royal Dutch Shell and related subsidiaries.

“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.
“Submarine fan”	A fan-shaped deposit of sediments occurring in a deep water setting where sediments have been transported via mass flow, gravity induced, processes from the shallow to deep water. These systems commonly develop at the bottom of sedimentary basins or at the end of large rivers.
"TAG GSA"	TEN Associated Gas - Gas Sales Agreement.
"TEN"	Tweneboa, Enyenra and Ntomme.
“Three-way fault trap”	A structural trap where at least one of the components of closure is formed by offset of rock layers across a fault.
"Tortue Phase 1 SPA"	Greater Tortue Ahmeyim Agreement for a Long Term Sale and Purchase of LNG.
"Trafigura"	Trafigura Group PTD, Ltd. and related subsidiaries including Trafigura Trading LLC.
“Trap”	A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate.
"Trident"	Trident Energy.
“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.
"WCTP"	West Cape Three Points.

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:

- the impact of the COVID-19 pandemic on the Company and the overall business environment;
- 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, as well as our ability to implement hedges addressing such volatility on commercially reasonable terms;
- 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, or new, environmental, health and safety or climate change or GHG laws, regulations and executive orders, or the implementation, or interpretation, of those laws, regulations and executive orders;
- 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 are intended 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.

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 the U.S. Gulf of Mexico, as well as a world-class gas development offshore Mauritania and Senegal. We also maintain a sustainable proven basin exploration program in Equatorial Guinea, Ghana and the U.S. Gulf of Mexico. Kosmos is listed on the NYSE and 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. 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 field in 2015 (which includes the Ahmeyim and Guembeul-1 discovery wells 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 discovered during that decade. 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 past few years, our business strategy has evolved to focus on production-enhancing in-fill 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 2017, together with access to surrounding exploration licenses, and bolstered by the 2018 acquisition of 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 deepwater E&P company, our mission is to safely 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 and stakeholders.

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 an efficient low cost exploration program in proven basins. 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 2023. In addition, our portfolio consists of a large inventory of leads and prospects in the proven basins where we have operations, which we plan to continue to mature for future drilling, providing us access to additional high return growth potential in the coming years.

Grow cash flow, proved reserves and production through exploitation, development, infrastructure-led exploration and basin opening exploration activities

We plan to grow cash flow, proved reserves and production by further exploiting our fields offshore Equatorial Guinea, Ghana, and the U.S. Gulf of Mexico. In Equatorial Guinea, our activity set is expanding beyond production optimization projects, such as utilizing electrical submersible pumps, to include development drilling and infrastructure-led exploration which, if successful, can be brought online quickly via subsea tieback to existing infrastructure. In Ghana, we plan to continue drilling additional development and production wells at both the Jubilee and TEN fields starting in 2021. In the U.S. Gulf of Mexico, we plan to continue development drilling in existing fields and drilling multiple infrastructure-led exploration targets. 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 the Phase 1 development of Greater Tortue Ahmeyim, growth is also expected to be realized through additional development phases of Greater Tortue Ahmeyim and through the development of all or a portion of our other discoveries in Mauritania and Senegal. During 2021, we plan to mature development concepts from previous discoveries in Mauritania, Senegal, the U.S. Gulf of Mexico and Equatorial Guinea, as well as drill additional infrastructure-led prospects in the U.S. Gulf of Mexico.

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. Our development of the Jubilee Field is an example of this approach. The Greater Tortue Ahmeyim development is also expected to be developed in a phased approach consistent with our business strategy. This is anticipated to result in first gas approximately eight years after initial discovery. Finally, our approach to discoveries in the U.S. Gulf of Mexico is to develop them via subsea tie-back to existing host facilities with spare capacity, which reduces development costs and the average timeline to first production.

Our returns focused exploration approach

Our exploration activity, which is deeply rooted in a fundamental, geologic approach, is focused on proven basins with high-graded infrastructure-led prospects and material play extension opportunities. We target specific areas with 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) attractive fiscal terms to maximize the commercial viability of discovered hydrocarbons. Alongside the subsurface analysis, Kosmos gains a thorough understanding of the “above-ground” dynamics in each of the countries in which we operate, which may influence a particular country’s relative desirability from an overall oil and natural gas operating and risk-adjusted return perspective.

Our approach is also 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. Acquisition of the Ceiba Field and Okume Complex in Equatorial Guinea and assets in the U.S. Gulf of Mexico have added high-quality prospectivity to our inventory of infrastructure-led exploration opportunities given their attractive acreage positions within proximity of existing infrastructure with excess capacity available. Existing infrastructure allows us to shorten the time cycle from discovery to first production, lower the capital requirements and increase the returns.

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.

We are led by an experienced management team with a successful track record. Our management team averages over 25 years of industry experience and has participated in discovering and developing multiple large-scale upstream projects around the world. Our experience, industry relationships and technical expertise are our core competitive strengths and are crucial to our success.

Secure a premium license to operate through industry-leading ESG performance

Kosmos recognizes that creating long-term shareholder returns can only be achieved by advancing the societies in which we work and operating in a manner that protects the environment. Kosmos focuses on continuously improving its ESG credentials by working with a range of stakeholders, including shareholders, partners, suppliers, host governments and civil society organizations.

The Company looks upon the United Nations Sustainable Development Goals as a useful template for evaluating and understanding how our activities promote economic and social progress in host countries. In 2013, we adopted the Kosmos Energy Business Principles to formalize our commitment to act as a force for good. Our Business Principles are supported by more detailed policies, procedures, and management systems. Each year, we report on our environmental, social, and governance practices and performance in our Sustainability Report and on our website.

Most recently, our ESG work has centered on evaluating the costs, benefits, risks, and opportunities that climate change and the global energy transition may present to our business, and integrating them into our business strategy. As part of this effort, we established governance structures to monitor and manage climate-related risks and opportunities; developed a strategy to measure and reduce greenhouse gas emissions from our own operations and mitigate remaining emissions through innovative nature-based solutions. In 2020, we published a Climate Risk and Resilience Report that adheres to the recommendations of the Task Force on Climate-related Disclosure (TCFD) and the Sustainability Accounting Standards Board (SASB) guidelines. The report reviews how we are identifying and managing climate-related risks and opportunities across four categories: Governance, Strategy, Risk Management, and Metrics and Targets. In addition, the report includes a commitment to achieve Scope 1 and Scope 2 carbon neutrality by 2030 or sooner, a full scenario analysis demonstrating the resilience of our portfolio including a scenario fully compliant with the goals of the Paris Agreement, and a description of innovative nature-based carbon capture projects used to mitigate emissions that cannot be eliminated.

Maintain financial discipline

Execution of our strategy requires us to maintain a conservative financial approach with a strong balance sheet, ample liquidity, and a commitment to low leverage. As of December 31, 2020, our liquidity was approximately $570 million.

Additionally, we use derivative instruments to partially limit our exposure to fluctuations in oil prices. 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, 2020, we have hedged positions covering approximately 12.0 million barrels of oil production in 2021. We also maintain insurance to partially protect against loss of production revenues from certain of our producing assets.

Operations by Geographic Area

We currently have operations in Africa and the U.S. Gulf of Mexico. Presently, our operating revenues are generated from our operations offshore Ghana, Equatorial Guinea, and the U.S. Gulf of Mexico. The following tables provide a summary of certain key 2020 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	9.7	44 %	$ 366,515	73	53 %
Equatorial Guinea	4.0	18 %	152,501	27	19 %
U.S. Gulf of Mexico	8.4	38	285,017	39	28 %
Total	22.1	100 %	$ 804,033	139	100 %

(1) For information concerning our estimated proved reserves as of December 31, 2020, see "—Our Reserves."

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	(8)
Big Bend	MC 697 / 698 / 742		5.3 %		Fieldwood	Production	(8)
Don Larsen	EB 598		20.0 %		Occidental	Production	(8)
Gladden	MC 800		20.0 %		W&T	Production	(8)
Kodiak	MC 727 / 771		29.1 %		Kosmos	Production	(8)
Marmalard	MC 255 / 300		11.4 %		Murphy	Production	(8)
Nearly Headless Nick	MC 387		21.9 %		Murphy	Production	(8)
Danny Noonan	EC 381 / GB 506		30.0 %		Talos	Production	(8)
Odd Job	MC 214 / 215		Various	(5)	Kosmos	Production	(8)
Sargent	GB 339		50.0 %		Kosmos	Production	(8)
SOB II	MC 431		11.8 %		Murphy	Production	(8)
S. Santa Cruz	MC 563		40.5 %		Kosmos	Production	(8)
Tornado	GC 281		35.0 %		Talos	Production	(8)
Winterfell	GC 944		16.4 %	(12)	Beacon	Appraisal	(8)
Mauritania							
Greater Tortue Ahmeyim	Block C8	(3)	26.8 %		BP	Development	2049(9)
Bir Allah	Block C8		28.0 %	(6)	BP	Appraisal	2022
Orca	Block C8		28.0 %	(6)	BP	Appraisal	2022
Senegal							
Greater Tortue Ahmeyim	Saint Louis Offshore Profond	(3)	26.7 %		BP	Development	2044(10)
Teranga	Cayar Offshore Profond		30.0 %	(7)	BP	Appraisal	2021
Yakaar	Cayar Offshore Profond		30.0 %	(7)	BP	Appraisal	2021
Equatorial Guinea(1)							
Ceiba Field and Okume Complex	Block G		40.4 %		Trident	Production	2029/2034(11)
Asam	Block S		40.0 %		Kosmos	Appraisal	2022

(1) For information concerning our estimated proved reserves as of December 31, 2020, see "—Our Reserves."

(2) The Jubilee Field straddles the boundary between the WCTP petroleum contract and the DT petroleum contract offshore Ghana. To optimize resource recovery in this field, we entered into the Jubilee UUOA in July 2009 with the 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. The interest percentage is subject to redetermination of the participating interests in the Jubilee Field pursuant to the terms of the Jubilee UUOA. Our current 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 the 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 Block areas. These interest percentages are subject to redetermination of the participating interests in the Greater Tortue Ahmeyim Field pursuant to the terms of the GTA UUOA. Our current payment interest on development activities in the Greater Tortue Ahmeyim Unit is 26.7%.

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

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

(6) SMHPM has the option to acquire up to an additional 4% participating interest in a commercial development on Block C8. These interest percentages do not give effect to the exercise of such option.

(7) PETROSEN has the option to acquire up to an additional 10% participating 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.

(8) 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.

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

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

(11) The Ceiba and Okume Complex are two approved fields within the Production Sharing Contract for Block G. Based on Commercial Discovery approval date for each field by the Ministry of Mines and Hydrocarbons, the Ceiba field Production Sharing Contract expires in 2029, and the Okume Complex field Production Sharing Contract expires in 2034.

(12) In January 2021, the Winterfell exploration well was successfully drilled at a working interest of 17.5%. Due to certain carry provisions in the lease exchange agreement, Kosmos now has a working interest of 16.4% in Green Canyon Block 944.

Exploration License and Lease Areas

Country	Number of Blocks	Kosmos Average Participating Interest		Operator(s)	Current Phase Expiration Range	
Equatorial Guinea	4	50.0%	(1)	Kosmos	2022	(6)
Mauritania	3	28.0%	(2)	BP	2021-2022	(6)
Sao Tome and Principe	1	59.0%	(3)	Kosmos	2022	(6)
Senegal	2	30.0%	(4)	BP	2021	(6)
South Africa	1	45.0%	(5)	Shell	2021	(6)
U.S. Gulf of Mexico	62	43.8%		Kosmos, Chevron, Murphy, Talos, Fieldwood, Occidental, W&T Offshore, LLOG, Beacon	through 2029	(7)

(1) Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest for all development and production operations.

(2) Should a commercial discovery be made, SMHPM’s 10% carried interest is extinguished and SMHPM will have an option to obtain a participating interest in the discovery area between 10% and 14%. 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.

(3) 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.

(4) PETROSEN has the option to obtain 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.

(5) The Republic of South Africa has the option to obtain a percentage of the participating interest ("State Option") in accordance with the provisions of the Applicable Laws prevailing at the time of the granting of a Production Right governing State Option requirements. During the third quarter of 2020, we entered into an agreement with Shell to farm down interests in a portfolio of frontier exploration assets. Under the agreement, Shell will acquire Kosmos' participating interest offshore South Africa. The transfer of Kosmos' participating interest is subject to customary conditions precedent, including approval by The Republic of South Africa which is expected during 2021.

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

(7) Our U.S. Gulf of Mexico blocks can be held by operations or commercial production, and the corresponding lease periods extend as long as governmental approved operations continue on the relevant block. This can extend the lease expiration to a date later than 2029.

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 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. 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 as part of the Jubilee Field Unit through the Jubilee FPSO and infrastructure, thus reducing their development cost. Pursuant to the Jubilee Field Unit Expansion Agreement, operatorship for the Mahogany and Teak discoveries transferred to Tullow with the approval of the GJFFDP by the Government of Ghana. The WCTP partners transferred operatorship of the remaining portions of the WCTP Block, to Tullow effective February 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 2020, the partnership exported approximately 72 million standard cubic feet per day (gross) on average from the Jubilee field to the mainland. In the absence of continuous export of large quantities of natural gas from the Jubilee Field, it is anticipated that we will need to re-inject or flare such natural gas. Our inability to continuously export associated natural gas 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 was completed in 2019. The catenary anchor leg mooring ("CALM") Buoy, the final phase of the Turret Remediation Project, was installed and commissioned in February 2021.

Oil production from the Jubilee Field averaged approximately 83,100 Bopd gross (19,000 Bopd net) during 2020.

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. The discoveries are being jointly developed with shared infrastructure and a single FPSO, with first oil produced in 2016.

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.

Oil production from TEN averaged approximately 48,700 Bopd gross (7,900 Bopd net) during 2020.

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 2017. In December 2017, we signed the TAG GSA. In 2020, the partnership exported approximately 15 million standard cubic feet per day (gross) on average from the TEN field to the mainland. Our inability to continuously export associated natural gas 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 protraction areas. After the acquisition, we have expanded our inventory through the U.S. Gulf of Mexico Federal lease sales and farm-in transactions, including expansion into the Walker Ridge, De Soto Canyon and Keathley Canyon areas of the U.S. Gulf of Mexico. Our U.S. Gulf of Mexico assets averaged approximately 22,800 Boepd net (~ 81% oil) from 13 fields during 2020.

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 Murphy. The technical team initially identified the Middle Miocene sands at the Odd Job prospect, and these sands are currently producing. The Odd Job 214 #2 well, the third well in the Odd Job field, was drilled in 2018, and came online in the fourth quarter of 2019. Net production during 2020 averaged approximately 8,100 Boepd net.

Tornado

The Tornado field is producing from three 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. To help enhance overall recoveries in the Tornado field, the Tornado 4 water injection well was drilled and came online in 2020. Net production during 2020 averaged approximately 4,700 Boepd net.

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 Murphy. Net production during 2020 averaged approximately 2,200 Boepd net.

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 was successfully drilled in the first half of 2020 and is anticipated to be brought online through existing infrastructure to the Devils Tower Spar platform in the first quarter of 2021. Net production during 2020 averaged approximately 3,200 Boepd net.

South Santa Cruz / Barataria

The South Santa Cruz field is producing from one well in a Late Miocene sand. The Barataria field is also producing from one well in a Late Miocene sand. Both fields produce through the Blind Faith semi-submersible platform, which is operated by Chevron. Net production from these two wells during 2020 averaged approximately 1,700 Boepd net.

Mauritania

The C8, C12, and C13 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.

These blocks cover an aggregate area of approximately 3.9 million acres (gross). We have acquired approximately 6,200 line-kilometers of 2D seismic data and 19,680 square kilometers of 3D seismic data covering portions of our blocks in Mauritania. Based on these 2D and 3D seismic programs, we have drilled three 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.

In the fourth quarter of 2020, Kosmos withdrew from Block C6 offshore 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 acquired approximately 7,500 square kilometers of 3D seismic data over the central and eastern portions of the Senegal Blocks in 2015. In 2016, we completed a 4,600 square kilometer survey over the western portions of the Senegal Blocks to fully evaluate the prospectivity. We have drilled three successful exploration wells and two appraisal wells.

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

Greater Tortue Ahmeyim Development

The Greater Tortue Ahmeyim discoveries 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 Block offshore Senegal.

We have drilled four wells within the Greater Tortue Ahmeyim development, Tortue-1, Guembeul-1, Ahmeyim-2 and Greater Tortue Ahmeyim-1 (GTA-1). 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.

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.

The Greater Tortue Ahmeyim-1 (GTA-1) appraisal well was drilled on the eastern anticline within the unit development area of Greater Tortue Ahmeyim field. The GTA-1 well encountered approximately 30 meters of net gas pay in high quality Albian reservoir. The well was drilled in approximately 2,500 meters of water, approximately 10 kilometers inboard of the Guembeul-1A and Tortue-1 wells, to a total depth of 4,884 meters.

In 2017, we completed a DST on 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 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. Following a competitive tender process, BP Gas Marketing was selected as the buyer for the LNG offtake for Greater Tortue Ahmeyim Phase 1, and the Tortue Phase 1 SPA was executed in February 2020. Phase 1 of the project was approximately 50% complete at year-end 2020, with first gas for the project expected in the first half of 2023. The partnership has also been focused on optimizing Phase 2 of the project to deliver competitive returns in the current environment. Phase 2 of the Greater Tortue Ahmeyim project targets an expansion largely utilizing the infrastructure from Phase 1.

Other Mauritania and Senegal Discoveries

BirAllah and Orca 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 Orca-1 well, located in Block C8 offshore Mauritania, was drilled in October 2019 and delivered a major gas discovery. The Orca-1 well, which targeted a previously untested Albian play, encountered 36 meters of net gas pay in excellent quality reservoirs. In addition, the well extended the Cenomanian play fairway by confirming 11 meters of net gas pay in a down-structure position relative to the original Marsouin-1 discovery well. The location of the Orca-1 well proved both the structural and stratigraphic components of the trap are working, thereby proving a significant volume. The Orca-1 well was drilled in approximately 2,510 meters of water to a total measured depth of around 5,266 meters.

In total, we believe that Orca-1 and Marsouin-1 have de-risked more than sufficient resource to support a world-scale LNG project from the Cenomanian and Albian plays in the BirAllah area. The BirAllah and Orca discoveries are being analyzed as a potential joint development.

Yakaar and Teranga Discoveries

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. In September 2019, we completed the Yakaar-2 appraisal well, which encountered approximately 30 meters of net gas pay. The Yakaar-2 well was drilled approximately nine kilometers from the Yakaar-1 exploration well and further delineated the southern extension of the field.

The results of the Yakaar-2 well underpin our view that the Yakaar-Teranga resource base is world-scale and has the potential to support an LNG project that provides significant volumes of natural gas to both domestic and export markets. Development of Yakaar-Teranga is being considered in a phased approach with Phase 1 providing domestic gas and data to optimize the development of future phases. It could also support the country’s “Plan Emergent Senegal” launched by the President of Senegal in 2014.

Equatorial Guinea

The EG-21, EG-24, S, and W blocks are located in the southern part of the Gulf of Guinea, in the Republic of Equatorial Guinea, west of the Rio Muni petroleum province with water depths up to 2,300 meters. These blocks are located in a proven petroleum system, with our primary targets being Cretaceous sands in structural and stratigraphic traps. We have over 10,000 square kilometers of 3D seismic over the blocks. The seismic data is being interpreted with the objective of high grading prospects for future drilling.

Ceiba Field and Okume Complex

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, which held 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 owned 50% of Hess International Petroleum Inc. Hess International Petroleum Inc. was subsequently renamed KTIPI. The transaction expanded our position in the Gulf of Guinea and provides 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.

Effective as of January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.4% undivided participating interest in the Ceiba Field and Okume Complex. As a result, our interest in the Ceiba Field and Okume Complex is accounted for under the proportionate consolidation method of accounting going forward. Oil production from the Ceiba Field and Okume Complex averaged approximately 33,600 Bopd gross (11,100 Bopd net) during 2020.

Asam Discovery

In October 2019, the S-5 exploration well was drilled to a total depth of 4,400 meters in Block S offshore Equatorial Guinea, encountering 39 meters of net oil pay in good-quality Santonian reservoir. The well is located within tieback range of the Ceiba FPSO and the appraisal program is currently ongoing to establish the scale of the discovered resource and evaluate the optimum development solution.

Sao Tome and Principe

We are the operator for the petroleum contract covering Block 5, offshore Sao Tome and Principe in the Gulf of Guinea. The block covers an area of approximately 0.5 million acres (gross) in water depths ranging from 2,150 to 3,000 meters and provides an opportunity to pursue the same core Cretaceous theme that was successful for us in Ghana.

Our block is adjacent to, and represents a potential 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.

In August 2017, we completed a 3D seismic survey of approximately 2,500 square kilometers offshore Sao Tome and Principe. Processing has been completed and the 3D seismic data has been integrated into our geological evaluation. We are compiling an inventory of prospects on the license area in Sao Tome and Principe and will continue to refine and assess the prospectivity.

Republic of South Africa

In September 2019, we completed a farm-in agreement with OK Energy to acquire a 45% non-operated interest in the Northern Cape Ultra Deep block offshore the Republic of South Africa. Shell owns 45% of the block and is the operator and OK Energy retained 10%. The petroleum contract covers approximately 6,930 square kilometers at water depths ranging from 2,500 to 3,100 meters and has an initial exploration phase of two years. In January 2021, a 2D seismic survey was acquired over Northern Cape Ultra Deep of approximately 500 line kilometers fulfilling the current phase work commitment. During the third quarter of 2020, we entered into an agreement with Shell to farm down interests in a portfolio of frontier exploration assets. Under the agreement, Shell will acquire Kosmos' participating interest in the Northern Cape Ultra Deep block offshore the Republic of South Africa. The transfer of Kosmos' participating interest is subject to customary conditions precedent, including approval by The Republic of South Africa which is expected during 2021.

Our Reserves

The following table sets forth summary information about our estimated proved reserves as of December 31, 2020. 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, 2020 and 2019 were associated with our fields in Ghana, Equatorial Guinea, and the U.S. Gulf of Mexico. Our estimated proved reserves as of December 31, 2018, were associated with our 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.

Summary of Oil and Gas Reserves

	2020 Net Proved Reserves(1)			2019 Net Proved Reserves(1)			2018 Net Proved Reserves(1)		
	Oil, Condensate, NGLs	Natural Gas(3)	Total	Oil, Condensate, NGLs	Natural Gas(3)	Total	Oil, Condensate, NGLs	Natural Gas(3)	Total
	(MMBbl)	(Bcf)	(MMBoe)	(MMBbl)	(Bcf)	(MMBoe)	(MMBbl)	(Bcf)	(MMBoe)
Reserves Category									
Proved developed									
Ghana(2)	26	23	30	47	31	52	48	33	54
Equatorial Guinea(4)	21	11	23	23	12	25	—	—	—
Mauritania/Senegal	—	—	—	—	—	—	—	—	—
U.S. Gulf of Mexico	32	25	36	34	28	39	33	25	37
Total proved developed	79	60	89	104	71	116	82	57	91
Proved undeveloped									
Ghana(2)	42	8	43	41	14	43	34	14	36
Equatorial Guinea(4)	4	—	4	3	—	3	—	—	—
Mauritania/Senegal	—	—	—	—	—	—	—	—	—
U.S. Gulf of Mexico	2	2	3	6	7	7	12	13	14
Total proved undeveloped(5)	48	10	50	50	21	53	45	28	50
Total Kosmos proved reserves	127	70	139	154	92	169	127	85	141
Equity method investment(4)							24	14	27
Total proved reserves							151	99	167

(1) Totals within the table may not add as a result of rounding.

(2) Our reserves associated with the Jubilee Field are based on the 54.4%/45.6% redetermination split between the WCTP Block and DT Block.

(3) These reserves include the estimated quantities of fuel gas required to operate the Jubilee and TEN FPSOs and Equatorial Guinea facilities 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 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.

(4) We disclosed our share of reserves that were accounted for by the equity method. Effective of January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.4% undivided participating interest in the Ceiba Field and Okume Complex. As a result, our interest in the Ceiba Field and Okume Complex is accounted for under the proportionate consolidation method of accounting going forward.

(5) 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.

Changes during the year ended December 31, 2020, were primarily due to 2020 production as well as lower prices. Greater Jubilee includes a negative revision of 0.3 MMBbl related to delayed drilling of water injection wells that will provide needed pressure support to certain production wells, in addition to net Greater Jubilee production of 7.0 MMBbl. Changes at TEN included a decrease of 12.0 MMBbl related to performance, delayed drilling and alterations to future development plans, in addition to net TEN production of 2.9 MMBoe. Changes at Equatorial Guinea included an increase of 2.0 MMBbl due to strong base performance and positive stimulation results, offset by 4.0 MMBbl of net Equatorial Guinea production. Changes at the U.S. Gulf of Mexico included an increase of 2.0 MMBoe primarily due to positive drilling and performance at Kodiak and Tornado, offset by net U.S. Gulf of Mexico production of 8.3 MMBoe.

During the year ended December 31, 2020, we had an overall proved undeveloped reserves decrease of 3.3 MMboe as a result of several factors, including adding additional wells to future development of Greater Jubilee (+4.7 MMboe), a negative revision in TEN (-0.3 MMboe), drilling of one well in TEN (-3.0 MMboe), one well in the Kodiak field (-1.6 MMboe) and one well in the Tornado field (-0.9 MMboe), and loss due to lower SEC pricing (-2.2 MMboe).

In TEN, we converted 3.0 MMboe of proved undeveloped reserves to proved developed with the drilling of a new well, at a cost of $28.5 million. In the U.S. Gulf of Mexico we spent $79.2 million to drill two new wells, which converted 2.5 MMboe of proved undeveloped reserves to proved developed.

The Tortue Phase 1 SPA was signed on February 11, 2020, resulting in approximately 100 MMBoe of proved undeveloped reserves being recognized at that time as evaluated by the Company's independent reserve auditor, Ryder Scott, LP. Due to the decrease in commodity prices during 2020 and the related commodity price utilized to calculate proved reserves for SEC purposes, the field did not have proved reserves recognition as of December 31, 2020.

Changes during the year ended December 31, 2019, at Greater Jubilee include a positive revision of 8.2 MMBbl related to positive drilling results and increased original oil in place, and optimized development plan, partially offset by net Greater Jubilee production of 7.6 MMBbl. Changes at TEN included an increase of 8.8 MMBoe related to original oil in place adjustments based on updated static modeling and development plan updates, partially offset by net TEN production of 3.8 MMBoe. Changes at Equatorial Guinea included an increase of 6.3 MMBbl due to production optimization plans and plans for new drilling, which was offset by 4.7 MMBbl of net production. Changes at the U.S. Gulf of Mexico included an increase of 2.9 MMBoe related to strong performance of certain fields and the Gladden Deep discovery, offset by net U.S. Gulf of Mexico production of 8.8 MMBoe.

During the year ended December 31, 2019, we had an addition of 16.1 MMBoe of proved undeveloped reserves as a result of several factors, including updated original oil in place due to positive drilling results and improved static models in Greater Jubilee and TEN, plans for one new well to be drilled in TEN and three new wells to be drilled in the Okume Complex.

We converted a total of 13.7 MMBoe of proved undeveloped reserves to proved developed due to completions of three new wells in Greater Jubilee, two new wells in TEN, and three new wells in the U.S. Gulf of Mexico with a combined cost of $176.7 million. We spent $41.6 million to convert 4.0 MMBbl of proved undeveloped reserves in Greater Jubilee and $12.8 million to convert 2.5 MMBoe proved undeveloped reserves in TEN; and $122.3 million spent to convert 7.2 MMBoe of proved undeveloped reserves in the U.S. Gulf of Mexico.

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 of 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 reserves in TEN incurring $9.7 million drilling a new well. We added 12.9 MMBbl of proved undeveloped reserves in Jubilee as a result of several factors, including additional data 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 the Mahogany area that is now part of the Greater Jubilee Unit. We incurred $27.2 million in drilling the two Jubilee wells, however, we note that we did not have a net migration of proved undeveloped reserves to proved developed reserves due to negative revisions in Jubilee proved developed reserves, which more than offset the effects of drilling two wells during the year.

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, 2020. All estimated future net revenues are attributable to projected production from Ghana, Equatorial Guinea and the U.S. Gulf of Mexico. 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 could be adversely affected.

	Estimated Future Net Revenues (in millions except $/Bbl)				
	Ghana	Equatorial Guinea	Mauritania / Senegal	U.S Gulf of Mexico	Total
Estimated future net revenues	$ 829	$ 57	$ —	$ 689	$ 1,575
Present value of estimated future net revenues:					
PV-10(1)	$ 531	$ 124	$ —	$ 579	$ 1,234
Future income tax expense (levied at a corporate parent and intermediate subsidiary level)	(251)	(131)	—	(7)	(389)
Discount of future income tax expense (levied at a corporate parent and intermediate subsidiary level) at 10% per annum	84	34	—	1	119
Standardized Measure(2)	$ 364	$ 27	$ —	$ 573	$ 964

Benchmark Dated Brent oil price($/Bbl)(3)	$ 41.77
Benchmark HLS oil price($/Bbl)(3)	$ 40.51
Benchmark Henry Hub gas price($/MMBtu)(3)	$ 1.99

(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 2020 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, 2020 for the respective benchmark. The benchmark price was adjusted for handling fees, transportation fees, quality, and a regional price differential.

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, 2020, 2019 and 2018 has been prepared by RSC, our independent reserve engineering firm for such years, in accordance with the rules and regulations of the 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 in accordance with SEC rules for proved reserves.

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, 2020 are based on costs in effect at December 31, 2020 and the 12-month unweighted arithmetic average of the first-day-of-the-month price for the year ended December 31, 2020, 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, 2020, 2019 and 2018, 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, 2020, 2019 and 2018, 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, 2020, 2019 and 2018 and related future net revenues and PV-10 at December 31, 2020, 2019 and 2018 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, 2020 reserve report was completed on January 22, 2021, and a copy is included as an exhibit to this report.

In connection with the preparation of the December 31, 2020, 2019 and 2018 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, 2020, 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.

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 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.

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, 2020 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
Equatorial Guinea	65	26	2,355	1,292	2,420	1,318
Mauritania	—	—	3,882	1,085	3,882	1,085
South Africa(3)	—	—	1,452	653	1,452	653
Sao Tome and Principe	—	—	527	310	527	310
Senegal	—	—	2,116	631	2,116	631
U.S. Gulf of Mexico	98	28	240	127	338	155
Total	326	86	10,606	4,105	10,932	4,191

(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, TEN, and Greater Tortue Ahmeyim 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 and our net acreage in Mauritania and Senegal may be affected by any redetermination of interests in the Greater Tortue Ahmeyim 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) The Company's interest in South Africa will transfer to Shell upon closing of the farm down transaction discussed in Note 3 — Acquisitions and Divestitures which is expected during 2021.

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, 2020:

	Productive Oil Wells		Productive Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Ghana	47	10.25	—	—	47	10.25
Equatorial Guinea	82	33.13	—	—	82	33.13
U.S. Gulf of Mexico	22	6.28	—	—	22	6.28
Total(1)	151	49.66	—	—	151	49.66

(1) Of the 151 productive wells, 38 (gross) or 9.05 (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)						Total	Total
	Productive(2)		Dry(3)		Total		Productive(2)		Dry(3)		Total			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Year Ended December 31, 2020														
Ghana	—	—	—	—	—	—	1	0.17	2	0.34	3	0.51	3	0.51
Equatorial Guinea	—	—	—	—	—	—	—	—	—	—	—	—	—	—
U.S. Gulf of Mexico	—	—	1	0.40	1	0.40	1	0.35	—	—	1	0.35	2	0.75
Total	—	—	1	0.40	1	0.40	2	0.52	2	0.34	4	0.86	5	1.26
Year Ended December 31, 2019														
Ghana	—	—	—	—	—	—	4	0.89	—	—	4	0.89	4	0.89
Equatorial Guinea	—	—	—	—	—	—	—	—	—	—	—	—	—	—
U.S. Gulf of Mexico	2	0.42	1	0.50	3	0.92	2	0.96	—	—	2	0.96	5	1.88
Total	2	0.42	1	0.50	3	0.92	6	1.85	—	—	6	1.85	9	2.77
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	0.30	1	0.30	—	—	—	—	—	—	1	0.30
Suriname	—	—	2	1.20	2	1.20	—	—	—	—	—	—	2	1.20
Total	—	—	6	2.30	6	2.30	5	1.44	—	—	5	1.44	11	3.74

(1) As of December 31, 2020, nine exploratory and appraisal wells have been excluded from the table until a determination is made if the wells have found proved reserves. Also excluded from the table are 15 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 activity from the U.S. Gulf of Mexico after the acquisition date.

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, 2020.

	Actively Drilling or Completing				Wells Suspended or Waiting on Completion			
	Exploration		Development		Exploration		Development	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Ghana								
Jubilee Unit	—	—	—	—	—	—	9	2.17
TEN	—	—	—	—	—	—	5	0.85
Equatorial Guinea								
Block S	—	—	—	—	1	0.40	—	—
U.S. Gulf of Mexico								
Winterfell	1	0.18	—	—	—	—	—	—
Kodiak 727 #3	—	—	1	0.29	—	—	—	—
Mauritania / Senegal								
Mauritania C8	—	—	—	—	2	0.56	—	—
Greater Tortue Ahmeyim Unit	—	—	—	—	3	0.80	1	0.27
Senegal Cayar Profond	—	—	—	—	3	0.90	—	—
Total	1	0.18	1	0.29	9	2.66	15	3.29

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, 2020, 131 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 2017, operatorship for the West Cape Three Points Block, including the Mahogany and Teak discoveries, transferred to Tullow in February 2018 and are now included in the Jubilee Unit. Kosmos is required to pay to the government of Ghana 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). 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 certain portions of 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.

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 to the government of Ghana 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). 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 certain portions of 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. To optimize resource recovery in the Jubilee Field, it was unitized and the Jubilee UUOA was agreed to in 2009 which governs each party’s respective rights and duties in the Jubilee Unit and named Tullow as the Unit Operator. 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. During the second quarter of 2019, SMHPM and PETROSEN elected to increase their respective interest in their portion of the Greater Tortue Ahmeyim Unit to the maximum allowed percentages under the respective petroleum contracts. After the election, our interest in the exploration areas of Block C8 offshore Mauritania and in Saint Louis Offshore Profound offshore Senegal are unchanged, however, our interest in the Greater Tortue Ahmeyim Unit is now 26.7% and is 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 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 obtain 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% (62% for gas) of total production prior to profit oil being split between the government of Mauritania and the contractor. Profit oil is then apportioned based upon “R-factor” tranches, where the R-factor is cumulative net revenues divided by the cumulative investment. At the election of the government of Mauritania, the government may receive its share of production in cash or in kind. A corporate tax rate of 27% is applied to profits at the license level. The terms of exploration periods of these Offshore Blocks are all ten years and initially included a first exploration period of four years followed by the second exploration period of three years and the third exploration period of three years. Kosmos is currently in the third exploration period for Blocks C8 and C12, expiring in June 2022. Kosmos is currently in the second exploration period for Block C13, having received a two year extension, now expiring in June 2021. This extension also reduced the third exploration period for Block C13 from three years to one year. 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.

Senegal Agreements

In June 2018, we entered the final renewal of the exploration period for the Senegal Cayar Offshore Profond and Saint Louis Offshore Profond Blocks, which lasts for approximately two and one-half years, ending in March 2021 for Cayar Offshore Profond and July 2021 for Saint Louis Offshore Profond. 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 on two separate occasions for a period of 10 years each 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. The Equatorial Guinean national oil company, 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 sub-period ending in March 2021. In August 2020, an extension was granted extending the first exploration sub-period ending to December 2022.

In the first quarter of 2019, we became operator of Block EG-24 offshore Equatorial Guinea. GEPetrol~~,~~ currently has a 20% carried interest during the exploration period. In March 2020, we entered the first extension period ending in March 2021. In August 2020, an extension was granted extending the first extension period to December 2022. The petroleum contract cover covers approximately 3,500 square kilometers. Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest for all development and production operations.

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 agreements with multiple oil marketing agents to market our share of the Jubilee and TEN fields oil, and we approve the terms of each sale proposed by such agent. We currently have an approximately four year marketing sales agreement over the Jubilee and TEN fields.

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.

In Equatorial Guinea, as provided under the petroleum 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. The continued economic disruption resulting from the COVID-19 pandemic could further materially impact the Company's business in future periods. Any potential disruption will depend on the duration and intensity of these events, which are highly uncertain and cannot be predicted at this time.

In February 2020, we, along with the co-venturers in the Greater Tortue Ahmeyim Field signed the Tortue Phase 1 SPA with BP Gas Marketing Limited to sell LNG free on board (FOB) from the Greater Tortue Ahmeyim Field located offshore Mauritania and Senegal. The annual contract quantity under the Tortue Phase 1 SPA is 127,951,000 MMBtu (the "ACQ") which is equivalent to approximately 2.45 million tonnes per annum, subject to limited downward adjustment by the sellers. The sales price for LNG under the Tortue Phase 1 SPA is set as a percentage of a crude oil price benchmark for the ACQ volumes (the "ACQ Sales Price"). The Tortue Phase 1 SPA has an initial term of up to twenty years that commences on the "Commercial Operations Date", which occurs after completion of certain LNG project facilities' performance tests.

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. Globally, the impact of COVID-19 has decreased demand for oil, which also resulted in significant declines in oil prices. Dated Brent crude, the benchmark for our international oil sales, ranged from approximately $13 to $70 per barrel during 2020. HLS crude, the benchmark for our U.S. Gulf of Mexico oil sales, which generally trades at a discount to Dated Brent, ranged from approximately $6 to $67 during 2020. Excluding the impact of hedges, our realized price for 2020 was $38.29 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

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 or for operations to continue;
- 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 are committed to continued compliance with all environmental laws and regulations applicable to our operations in all countries in which we do business. We have established policies, operating procedures and training programs designed to limit the environmental impact of our operations and to identify and comply with changes in existing laws and regulations, however the cost of compliance with more stringent laws and regulations in the future could have a material adverse effect on our financial condition and results of operations.

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

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 and was not the operator for any operations during 2020.

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)

Effective January 1, 2019, Trident became operator of the Ceiba Field and Okume Complex. In addition, Kosmos drilled an exploration well in 2019 after joining the Equatorial Guinea Oil and Gas Operators Emergency Resource Allocation Agreement to share equipment with other in country operators in case of emergency. Our membership in OSRL provided access to Tier II and III equipment located in Accra, Ghana and Southampton, England, UK.

Sao Tome and Principe (Operated)

Kosmos began the Oil Spill Contingency Planning process in 2019. Kosmos continues to support the government of Sao Tome and Principe with the development of their National Oil Spill Contingency Plan to enable them to access the International Oil Pollution Compensation Funds to respond to third party incidents.

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.

Human Capital Resources

Health and Safety

The health and safety of our employees and those that work with us is a priority for Kosmos. Employees and contractors are expected to take all necessary and reasonable actions to ensure safe operations by following safe work practices, complying with relevant policies and regulations, and completing all applicable training. To support our dedication to health, safety and the environment, the company has a comprehensive Health, Safety, Environment and Security ("HSES") management system that applies to all Kosmos employees and contractors known as “The Standard.” In addition to adoption of The Standard, Kosmos fosters a strong safety culture through online and in person training, regular emergency response drills, and impactful safety discussions.

With the onset of the coronavirus pandemic, a priority for 2020 was ensuring the health of our employees and contractors through an action plan focused on remote working as the default for employees normally based in the office and safeguarding operations offshore through a variety of enhanced operational safeguards and monitoring measures, including strict pre-embarkation quarantine procedures, wellness screenings, and COVID-19 testing.

Culture, Engagement and Development

Kosmos aims to be a world-class company known for delivering results and being a workplace of choice. We pride ourselves on our ability to provide employees with careers that are professionally challenging, personally rewarding, and focused on delivering value. We aim to provide a stimulating and rewarding work environment through an inclusive culture that promotes entrepreneurial thinking, facilitates teamwork, and embraces ethical behavior.

Kosmos is committed to investing in the development of our employees. We support development through a blend of learning approaches including in-person and virtual training opportunities, on-the-job training, conferences, cross team projects and experiences and our leadership development program. Each year, all employees also have an opportunity to provide feedback on the employee experience and Kosmos culture through our annual employee opinion survey. In 2020, Kosmos achieved top quartile performance relative to peer companies. The feedback received through this annual survey is used to support continuous improvement and enhance the overall employee experience. In 2020, Kosmos had a retention rate greater than 95%.

Diversity and Inclusion

Kosmos focuses on recruiting, retaining, and developing a diverse and inclusive workforce that embraces our values and culture. We seek to promote diversity in our workforce both because it is the right thing to do and because it gives us access to the widest range of talents. Through social and educational events that address the different backgrounds and identities of employees, Kosmos helps foster a spirit of inclusion across the company. We promote and celebrate the array of diverse perspectives and experiences of Kosmos employees and applicants, whether in terms of race, ethnicity, sex, gender, sexual orientation, gender expression, religion, national origin, disability, or experiences.

We seek to employ qualified individuals from the countries in which we operate and are proud of our record of recruitment and retention of local staff. This year we achieved 100% local employees across all our host country offices including all our country managers.

As of December 31, 2020, we had 252 employees with 209 being based in the United States and 43 residing in our local offices. Our workforce was approximately 37% gender diverse and approximately 31% minority.

Employee Well-being

Kosmos offers employees a robust range of benefits, including health plans, equity opportunities, savings plans, short- and long-term incentives. All domestic employees are awarded equity in the company as part of the total reward package, aligning employee reward with shareholder interest. Our benefits package prioritizes emotional, physical, and financial health and wellness. We also offer a robust Employee Assistance Program (EAP), which offers free and confidential assessments, counseling, and follow-up services to employees with personal and/or work-related mental health problems.

These benefits are intended to both promote the long-term health and well-being of our employees and increase employee engagement and retention. Additionally, we believe that these benefits help facilitate a strong work-life balance and a culture that prioritizes overall employee wellness.

Corporate Information

In December 2018, Kosmos Energy Ltd. changed our jurisdiction of incorporation from Bermuda to the State of Delaware, USA. 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.

Available Information

Kosmos is listed on the NYSE and LSE 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.

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.

Summary Risk Factors

Our business is subject to a number of risks, including risks that may prevent us from achieving our business objectives or may adversely affect our business, financial condition, results of operations, cash flows, and prospects. These risks are discussed more fully below and include, but are not limited to, risks related to:

Risks Relating to our Oil and Natural Gas Operations

- We have limited proved reserves;
- We face substantial uncertainties in estimating the characteristics of our discoveries and our prospects;
- Drilling wells is speculative and may not result in any discoveries;
- Development wells may not result in commercially productive quantities of oil and gas reserves;
- Our identified drilling and infrastructure locations are scheduled out over time, making them susceptible to uncertainties;
- We are contractually obligated to drill wells and declare any discoveries in order to retain exploration and production rights;
- Inability of third parties who contract with us to meet their obligations may adversely affect our financial results;
- The unit partners' respective interests in the Jubilee Unit and Greater Tortue Ahmeyim Unit are subject to redetermination;
- We are not the operator on all of our license areas and facilities and do not hold all of the working interests in certain of our license areas;
- Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate;
- 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;
- We may not be able to commercialize our interests in any natural gas produced from our license areas;
- 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;
- We are subject to numerous risks inherent to the exploration and production of oil and natural gas;
- We are subject to drilling and other operational and environmental risks and hazards;
- Our operations may be materially adversely affected by tropical storms and hurricanes;
- The development schedule of oil and natural gas projects is subject to delays and cost overruns;
- Our offshore and deepwater operations involve special risks that could adversely affect our results of operations;
- We have had disagreements with host governments regarding certain of our rights and responsibilities and may have future disagreements with our host governments;
- The geographic locations of our licenses in Africa subject us to an increased risk of loss of revenue or curtailment of production from factors specifically affecting those areas;

Risks Relating to our Business and Financial Condition

- COVID-19 pandemic and outbreaks of other diseases may adversely affect our business operations and financial condition;
- A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition and results of operations;
- Our business plan requires substantial additional capital;
- 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;

- We face various risks associated with increased activism against, or change in public sentiment for, oil and gas exploration and development activities;
- Deterioration in the credit or equity markets could adversely affect us;
- 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;
- Slower global economic growth rates may materially adversely impact our operating results and financial position;
- Increased costs and availability of capital could adversely affect our business;
- Our derivative activities could result in financial losses or could reduce our income;
- Our commercial debt facility, revolving credit facility, indenture governing the Senior Notes and GoM Term Loan contain certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions;
- Provisions of our Senior Notes could discourage an acquisition of us by a third party;
- Our level of indebtedness may increase and thereby reduce our financial flexibility;
- We are a holding company and our ability to make payments on our outstanding indebtedness is dependent upon the receipt of funds from our subsidiaries;
- We may be subject to risks in connection with acquisitions and the integration of significant acquisitions may be difficult;
- If we fail to realize the anticipated benefits of a significant acquisition, our results of operations may be adversely affected;
- A cyber incident could result in information theft, data corruption, operational disruption, and/or financial loss;
- Outbreaks of disease may adversely affect our business operations and financial condition;
- Our ability to utilize net operating loss carryforwards may be subject to certain limitations;
- Changes in the method of determining LIBOR, or the replacement of LIBOR with an alternative reference rate, may adversely affect interest expense related to outstanding debt;

Risks Relating to Regulation

- Our business, operations and financial condition may be directly and indirectly adversely affected by political and economic circumstances;
- More comprehensive and stringent regulation in the U.S. Gulf of Mexico has materially increased costs and delays in offshore oil and natural gas exploration and production operations;
- The oil and gas industry is intensely competitive and many of our competitors possess and employ substantially greater resources than us;
- 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;
- We are subject to numerous health, safety and environmental laws and regulations which may result in material liabilities and costs;
- We may be exposed to assertions concerning or liabilities under anti-corruption laws;
- Federal regulatory law could have an adverse effect on our ability to use derivative instruments;

General Risk Factors

- We are dependent on certain members of our management and technical team;
- We operate in a litigious environment;
- We face various risks associated with global populism;
- Our share price may be volatile, and purchasers of our common stock could incur substantial losses;
- A substantial portion of our total issued and outstanding common stock may be sold into the market at any time; and
- Holders of our common stock will be diluted if additional shares are issued.

Risks Relating to our Oil and Natural Gas Operations

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, other production facilities 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 Sao Tome and Principe license has not yet proved to be an economically viable production area. 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 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.

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 international 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.

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 contracts 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, 2020, we have unfulfilled drilling and data acquisition obligations in two 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 certain portions of 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 oil marketing companies, 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 each 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.

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, the Greater Tortue Ahmeyim Unit or certain producing fields in the U.S. Gulf of Mexico and do not hold operatorship in certain other offshore blocks. 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, 2020.

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 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 international 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 international 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, 2020, the Jubilee partners have provided approximately 131 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 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 LNG market. However, that plan is contingent on making additional 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 online, 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 2017. However, the uptime of the pipeline and processing facilities in future periods is not known. In the absence of the continuous removal 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. If we are unable to resolve potential issues related to the continuous removal of associated natural gas, our oil production will be negatively impacted.

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

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

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

In the event that our currently undeveloped discoveries and prospects are developed and become operational, they may not produce oil and natural gas in commercial quantities or at the costs anticipated, and our projects may cease production, in part or entirely, in certain circumstances. Discoveries may become uneconomic as a result of an increase in operating costs to produce oil and natural gas. Our actual operating costs and rates of production may differ materially from our current estimates. Moreover, it is possible that other developments, such as increasingly strict environmental, climate change, health and safety laws, regulations and executive orders 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 well sites 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.

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 the turret bearing issue on the FPSO. The equipment downtime caused by these mechanical issues negatively impacted oil production during the year.

Furthermore, deepwater operations generally, and operations in Africa, 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 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 host governments regarding certain of our rights and responsibilities and may have future disagreements with our host governments.

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, development or production activities, our ability to operate, our rights under our licenses and local laws or our rights to monetize our interests.

As an example, 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.

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

A large portion of our current exploration licenses are located in Africa. 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 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.

Risks Relating to our Business and Financial Condition

The COVID-19 pandemic and outbreaks of other diseases may adversely affect our business operations and financial condition.

The global spread of the COVID-19 pandemic, travel restrictions, "shelter-in-place" measures and other governmental actions taken to inhibit its spread, has created significant volatility, uncertainty and economic disruption in the markets in which we operate, which has affected our business and operations and those of our suppliers, contractors and partners. Certain contracts necessary for our ongoing exploration, development and production operations have been suspended or terminated as a consequence of the pandemic, and the pandemic has constrained our ability and the ability of our suppliers, contractors and partners to develop and implement effective plans to explore for oil and gas and to develop or produce certain of our license areas. The measures taken to combat the pandemic have limited access to qualified personnel, increased costs associated with ensuring the safety and health of our personnel, restricted the transportation of personnel, equipment and supplies to and from our areas of operation, and they have diverted the time, attention and resources of government agencies that are necessary to conduct our operations.

Access to our FPSOs and other production facilities could also be restricted and/or suspended as result of COVID-19. Our FPSOs and production facilities are able to operate for short periods of time without access to the mainland, but if travel restrictions continue, we and the operators of the impacted fields could be required to cease production and other operations until such restrictions were lifted. Any losses we experience as a result of COVID-19 that impact sales or delay production may not be covered by our insurance policies.

The extent to which our results are affected by COVID-19 will largely depend on future developments that cannot be accurately predicted. While the full impact of this outbreak is not yet known, we are closely monitoring the spread of COVID-19 and continually assessing its potential effects on our liquidity, capital resources, operations and business and those of the third parties we rely on. In addition, the adverse effect of the COVID-19 pandemic on our business, results of operations, financial condition and cash flows may heighten many of the other risks described in the "Risk Factors" section of this report and our Annual Report on Form 10-K for the fiscal year ended December 31, 2020.

Significant outbreaks of other contagious diseases or adverse public health developments could also have a material impact on our business operations and financial condition. Many of our operations are currently in developing countries that are susceptible to outbreaks of disease, such as the Ebola epidemic in 2014 and 2015 in West Africa and may lack the resources to effectively contain such an outbreak quickly.

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

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

- changes in supply and demand for oil and natural gas;
- the actions of the Organization of the Petroleum Exporting Countries;
- speculation as to the future price of oil and natural gas and the speculative trading of oil and natural gas futures contracts;
- global economic conditions;
- political and economic conditions, including embargoes in oil-producing countries or affecting other oil-producing activities, particularly in the Middle East, Africa, Russia and Central and South America;

- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil inventories and oil refining capacities;
- weather conditions and natural or man-made disasters;
- technological advances affecting energy consumption;
- governmental regulations and taxation policies;
- proximity and capacity of transportation facilities;
- the development and exploitation of alternative fuels or energy sources;
- the price and availability of competitors' supplies of oil and natural gas; and
- the price, availability or mandated use of alternative fuels or energy sources.

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

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

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

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

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

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 face various risks associated with increased activism against, or change in public sentiment for, 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 and other stakeholders 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;
- pressure or requirements for more analysis and disclosure of environmental and climate change-related risks;

- damaging publicity about us;
- increased regulation;
- 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 may continue to increase if the Biden administration in the U.S. is perceived to be following, or actually follows, through on President Biden's campaign commitments to promote decreased fossil fuel exploration and production in the U.S. In addition, activism may continue to increase as a result of President Biden's environmental and climate change executive orders described later in this 10-K in the risk factor titled "*Our business, operations and financial condition may be directly and indirectly adversely affected by political and economic circumstances, and changes in laws and regulations, in the countries and regions in which we operate.*" 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. In addition, a change in public sentiment regarding the oil and gas industry could result in a reduction in the demand for our products or otherwise affect our results of operations or financial condition.

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.

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 and availability 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;
- 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.

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. In addition, a reduction in our ability to access credit could reduce our ability to implement derivative arrangements on commercially reasonable terms.

Our commercial debt facility, revolving credit facility, indenture governing the Senior Notes and GoM Term Loan 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, indenture governing the Senior Notes and GoM Term Loan 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, the indenture governing the Senior Notes or the GoM Term Loan 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, the revolving credit facility and the GoM Term Loan, our capital expenditures that we can fund with the proceeds of our commercial debt facility, revolving credit facility and GoM Term Loan.

Our commercial debt facility, revolving credit facility and GoM Term Loan 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 move funds among our subsidiaries, operate our business, or expand or pursue our business strategies. Our ability to comply with these and other provisions of our commercial debt facility, revolving credit facility, indenture governing the Senior Notes and GoM Term Loan 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, indenture governing the Senior Notes and GoM Term Loan, 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, indenture governing the Senior Notes and GoM Term Loan, 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, indenture governing the Senior Notes and GoM Term Loan 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 indenture governing the Senior Notes and GoM Term Loan 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.

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

At December 31, 2020, we had $1.2 billion outstanding and $120.0 million of committed undrawn available capacity under our commercial debt facility, subject to borrowing base availability. As of December 31, 2020, we had $100 million outstanding under the Corporate Revolver and the undrawn availability was $300.0 million. As of December 31, 2020, we had $650.0 million principal amount of Senior Notes outstanding and $200 million outstanding under the GoM Term Loan. 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 to provide cash to us through dividend, debt repayment or intercompany lending. In the event that we 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.

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. 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 may adversely affect our business operations and financial condition.

Significant outbreaks of contagious diseases, and other adverse public health developments, could have a material impact on 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.

The ongoing coronavirus outbreak emanating from China at the beginning of 2020 has resulted in increased travel restrictions and extended shutdown of certain businesses in the region. These or any further political or governmental developments or health concerns could result in social, economic and labor instability. These uncertainties could have a material impact on our business operations and financial condition.

Our ability to utilize net operating loss carryforwards may be subject to certain limitations.

Our ability to use our federal and state net operating losses to offset potential future taxable income and related income taxes that would otherwise be due is dependent upon our generation of future taxable income, including where our state losses are subject to expiration, before such state net operating losses expire, and we cannot predict with certainty when, or whether, we will generate sufficient taxable income to use all of our net operating losses. In addition, Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), contains rules that impose an annual limitation on the ability of a company with federal net operating loss carryforwards that undergoes an ownership change, which is generally any change in ownership of more than 50% of its stock (by value) over a three-year period, to utilize its federal net operating loss carryforwards in years after the ownership change. These rules generally operate by focusing on ownership changes among holders owning directly or indirectly 5% or more of the shares of stock of a company or any change in ownership arising from a new issuance of shares of stock by such company. If a company's income in any year is less than the annual limitation prescribed by Section 382 of the Code, the unused portion of such limitation amount may be carried forward to increase the limitation in subsequent tax years.

If we were to undergo an ownership change as a result of future transactions involving our common stock, including a follow-on offering of our common stock or purchases or sales of common stock between 5% holders, our ability to use our federal net operating loss carryforwards may be subject to limitation under Section 382 of the Code. If our federal net operating losses become subject to the limitation under Section 382 of the Code, we may be unable to fully utilize our federal net operating loss carryforwards to offset our taxable income, if any, in future years, which could have a negative impact on our financial position and results of operations.

In addition to the aforementioned federal income tax implications pursuant to Section 382 of the Code, most states follow the general provisions of Section 382 of the Code, either explicitly or implicitly resulting in separate state net operating loss limitations. Any limitation on our ability to use our state net operating loss carryforwards could also have a negative impact on our financial position and results of operations.

Changes in the method of determining London Interbank Offered Rate ("LIBOR"), or the replacement of LIBOR with an alternative reference rate, may adversely affect interest expense related to outstanding debt.

On July 27, 2017, the Financial Conduct Authority in the United Kingdom announced that it would no longer persuade or compel panel banks to submit the rates required to calculate LIBOR after the end of 2021. The announcement indicates that the continuation of LIBOR on the current basis cannot and will not be guaranteed after 2021. The continued existence of LIBOR after 2021, therefore, remains highly uncertain. While various governmental working groups are pursuing replacement rates, if LIBOR ceases to exist, we may need to renegotiate our Facility and Corporate Revolver and may not be able to do so on terms that are favorable to us.

Risks Relating to Regulation

Our business, operations and financial condition may be directly and indirectly adversely affected by political and economic circumstances, and changes in laws and regulations, in the countries and regions in which we operate.

Oil and natural gas exploration, development and production activities are directly and indirectly subject to political and economic uncertainties (including but not limited to those resulting from government elections and changes in energy policies), changes in laws and policies governing operations of companies, expropriation of property, cancellation or modification of contract rights, revocation of consents, approvals or royalty regimes, obtaining various approvals from regulators, foreign exchange restrictions, currency fluctuations, royalty increases, implementation of a carbon tax or cap-and-trade program, and other risks arising out of 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. As an example, following the election and inauguration of President Biden in January 2021, the U.S. Secretary of the Interior issued Order No. 3395 on January 20, 2021 (the "Secretary of the Interior Order"), which, among other things, placed a 60-day moratorium on oil and gas leases, lease amendments and extensions, and drilling permits, on federal lands or offshore waters. We are reviewing the Secretary of the Interior Order, and while it is too soon to determine its impact on our business, financial condition and results of operations, any such impacts could be material.

In addition, the Biden administration has taken a number of actions that may result in stricter environmental, health and safety standards applicable to our operations and those of the oil and gas industry more generally. The Biden Administration issued the "Executive Order on Tackling the Climate Crisis at Home and Abroad" on January 27, 2021 (the "Climate Change Executive Order"). This executive order directed the Secretary of the Interior to halt indefinitely new oil and natural gas leases on federal lands and offshore waters pending completion of a review by the Secretary of the Interior of federal oil and gas permitting and leasing practices in light of the Biden administration's concerns regarding the impact of these activities on the environment and climate. In addition, the Climate Change Executive Order, among other things, establishes climate conditions as an essential element of U.S. foreign policy; establishes a White House office and a climate task force to coordinate and implement the Biden Administration's domestic climate change agenda; directs federal agencies to procure carbon pollution-free electricity and zero-emission vehicles; eliminate fossil fuel subsidies as consistent with applicable law; identifies a goal of a carbon pollution-free power sector by 2035 and a net-zero emissions U.S. economy by 2050; and commits to a goal of conserving at least 30 percent of federal lands and oceans by 2030. Separately, President Biden signed another executive order on January 20, 2021, titled "Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis" (the "Health and Environment Executive Order"), which among other things calls for a review of regulations and other executive actions promulgated, issued or adopted during the prior Presidential administration to assess whether they are, in the view of the Biden Administration, sufficiently protective of public health and the environment, including with respect to climate change, and consistent with science. The order also specifically calls for consideration of new regulations regarding methane emissions in the oil and gas sector, reassessment of decisions made by the prior administration limiting the size of certain national monuments, and incorporation of the impact of GHG emissions (known as the "social cost of carbon") in decision making by federal agencies. These actions and any future changes to applicable environmental, health and safety, regulatory and legal requirements promulgated by the current Presidential administration and Congress may restrict our access to additional acreage and new leases in the deepwater U.S. Gulf of Mexico or lead to limitations or delays on our ability to secure additional permits to drill and develop our acreage and leases or otherwise lead to limitations on the scope of our operations, or may lead to increases to our compliance costs. The potential impacts these changes on our future consolidated financial condition, results of operations or cash flows cannot be predicted.

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. We have faced similar tax related disputes with the Senegal Tax Administration.

Additionally, monetary sector reform initiatives in the West African Monetary Union and the Central African Economic and Monetary Union, such as through the implementation of Regulation 02/18/ECMAC/UMAC/CM by the Bank of Central African States could restrict or prevent payments being made in a foreign currency; impose restrictions on offshore and onshore foreign currency accounts; and/or restrict or prevent the repatriation of revenues and debt proceeds. The implementation or realization of any of the foregoing could have an adverse impact on our financial condition and results of operations.

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.

More comprehensive and stringent regulation in the U.S. Gulf of Mexico has materially 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 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 May 15, 2019, BSEE published a final rule with an effective date of July 15, 2019 that revises requirements for well design, well control, casing, cementing, real-time monitoring (RTM), and subsea containment. These revisions modify regulations pertaining to offshore oil and gas drilling, completions, workovers, and decommissioning in accordance with Executive and Secretary of the Interior's Orders. Key features of the well control regulations include requirements for blowout preventers (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. For a discussion of recent drilling and climate change executive orders signed by President Biden, see the risk factor earlier in this 10-K titled “*Our business, operations and financial condition may be directly and indirectly adversely affected by political and economic circumstances, and changes in laws and regulations, in the countries and regions in which we operate*.”

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. Any other new rules, regulations or legal initiatives by BOEM or other governmental authorities, including as a result of the current Presidential administration, that impose more stringent requirements regarding financial assurances, moratoria on new leases or otherwise adversely affecting our offshore activities could result in increased costs. In particular, the current Presidential administration supports limitations on oil and gas exploration and production on federal areas. As noted above, President Biden's January 20, 2021 executive order included limitations on oil and gas exploration and production in the Arctic Refuge and may result in the redesignation of certain federal lands as national monuments. In addition, on January 20, 2021, the Department of the Interior placed a 60-day moratorium on new oil and gas leases and drilling permits on federal lands. President Biden issued another executive order on January 27, 2021, which, among other things, halts indefinitely new oil and natural gas leases on federal lands and offshore waters pending completion of a review by the Secretary of the Interior of federal oil and gas permitting and leasing practices in light of the administration's concerns regarding the impact of these activities on the environment and climate. These restrictions and similar restrictions that may be issued in the future may limit our operations and adversely impact our future financial results.

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.

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.

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 and the U.S., signed and officially entered into an international climate change accord (the "Paris Agreement"). Although the U.S. officially withdrew from the Paris Agreement on November 4, 2020, on January 20, 2021, President Biden began the 30-day process of rejoining the Paris Agreement, which will become effective for the U.S. on February 19, 2021. 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 and Senegal, are parties. In 2012, the Kyoto Protocol was extended by amendment through 2020 in the so-called Doha Amendment, which entered into force in late December 2020 after the requisite number of parties ratified it in October 2020. It cannot be determined at this time what effect the Paris Agreement, and any related GHG emissions targets, regulations, executive orders or other requirements, will have on our business, results of operations and financial condition. This legislative and 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. For a discussion of recent environmental and climate change executive orders signed by President Biden, see the risk factor earlier in this 10-K titled "*Our business, operations and financial condition may be directly and indirectly adversely affected by political and economic circumstances, and changes in laws and regulations, in the countries and regions in which we operate.*"

Health, safety and environmental laws and regulations 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 may be exposed to assertions concerning or liabilities under the U.S. Foreign Corrupt Practices Act and other anti-corruption laws, and any such assertions or determination that we violated the U.S. Foreign Corrupt Practices Act or other such laws could result in significant costs to Kosmos and 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 or other anti-corruption laws 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.

While we believe we maintain a robust compliance program (including policies, procedures, and controls) and corresponding compliance culture, from time-to-time assertions may be raised, including by media outlets or competitors, related to our operations or assets which, notwithstanding the lack of veracity of such assertions, may attract the interest of regulators or affect the market perception of Kosmos. On June 3, 2019, the BBC *Panorama* broadcast a television program, which included various assertions concerning the Cayar Offshore Profond and Saint Louis Offshore Profond Blocks offshore Senegal in which the Company holds interests, which we believe are inaccurate and misleading. We, BP (block operator) and the Government of Senegal all promptly issued independent statements strongly refuting these assertions. As noted in our statement, Kosmos conducted extensive pre-transaction due diligence, and we believe we acquired our interests in the blocks in compliance with applicable laws. After the program aired, certain government agencies requested that Kosmos voluntarily provide information related to the Senegal blocks and other blocks. We are cooperating with these requests to ensure that these agencies have an accurate and complete understanding concerning the history of the blocks. There can be no assurance that these or other regulatory bodies will not make further regulatory inquiries or take other actions.

Federal regulatory law could have an adverse effect on our ability to use derivatives to reduce the effect of commodity price, interest rate and other risks associated with our business.

At times, we use derivatives, specifically cash-settled commodity options and interest rate swaps, to hedge risks associated with our business, including commodity price and interest rate risk. The Commodity Futures Trading Commission ("CFTC") has jurisdiction over derivatives, including swaps and cash-settled commodity options, which are regulated as swaps under the Commodity Exchange Act.

Of particular importance to us, the CFTC has recently finalized new regulations that establish position limits for certain futures and economically equivalent swaps and require exchanges to do the same. Certain bona fide hedging positions are exempt from these position limits. As the relevant provisions of these rules for the Company are phased in over the next several years, they may increase costs or, if we are unable to meet the specific requirements of the relevant hedging exemption, we may be subject to certain position limits.

The CFTC has designated certain interest rate swaps for mandatory clearing and exchange trading. The CFTC has not yet proposed rules designating any other classes of swaps, including commodity swaps, for mandatory clearing or exchange trading. The application of the mandatory clearing and trade execution requirements may change the cost and availability of the swaps that the Company uses for hedging.

Swap dealers that we transact with need to comply with margin and segregation requirements for uncleared swaps. While our uncleared swaps are not directly subject to those margin requirements as a result of the fact that they are used by us for hedging purposes, due to the increased costs to dealers for transacting uncleared swaps in general, our costs for these transactions may increase.

The Commodity Exchange Act also requires certain of the counterparties to our derivatives instruments to be registered with the CFTC and be subject to substantial regulation. These requirements could significantly increase the cost of derivatives, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivatives. If we reduce our use of derivatives as a result of these 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 have also implemented or are implementing similar 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. The impact of such regulations could be similar to those described above with respect to U.S. rules.

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

General Risk Factors

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, develop, and produce 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.

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.

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.

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;
- 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 materially, 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.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Common Stock Trading Summary

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

As of February 19, 2021, 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 104. On February 19, 2021, the last reported sale price of Kosmos' common stock, as reported on the NYSE, was $2.74 per share.

In March 2020, in response to economic conditions, including oil price volatility and the impact of COVID-19 pandemic, the Board of Directors decided to suspend the dividend. 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. 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, the Corporate Revolver, and the GoM Term Loan unless we meet certain conditions, financial and otherwise.

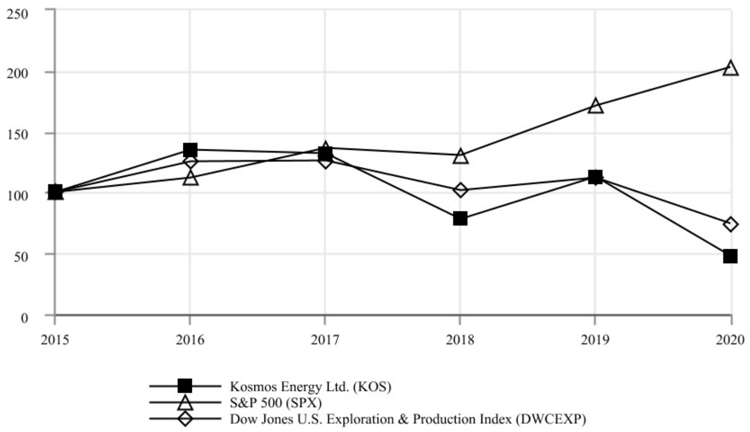
Issuer Purchases of Equity Securities

Under the terms of our 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. During 2020, there were no shares purchased.

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, 2020, 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,					
	2015	**2016**	**2017**	**2018**	**2019**	**2020**
Kosmos Energy Ltd. (KOS)	$ 100.00	$ 134.81	$ 131.73	$ 78.27	$ 112.96	$ 47.38
S&P 500 (SPX)	100.00	111.95	136.38	130.39	171.44	202.96
Dow Jones U.S. Exploration & Production Index (DWCEXP)	100.00	125.71	126.06	101.73	112.20	74.30

Item 6. Selected Financial Data

The following selected consolidated financial information set forth below as of and for the five years ended, December 31, 2020, 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,				
	2020	2019	2018	2017	2016
	(In thousands, except per share data)				
Revenues and other income:					
Oil and gas revenue	$ 804,033	$ 1,499,416	$ 886,666	$ 578,139	$ 310,377
Gain on sale of assets	92,163	10,528	7,666	—	—
Other income, net	2	(35)	8,037	58,697	74,978
Total revenues and other income	896,198	1,509,909	902,369	636,836	385,355
Costs and expenses:					
Oil and gas production	338,477	402,613	224,727	126,850	119,367
Facilities insurance modifications, net	13,161	(24,254)	6,955	(820)	14,961
Exploration expenses	84,616	180,955	301,492	216,050	202,280
General and administrative	72,142	110,010	99,856	68,302	87,623
Depletion, depreciation and amortization	485,862	563,861	329,835	255,203	140,404
Impairment of long-lived assets	153,959	—	—	—	—
Interest and other financing costs, net	109,794	155,074	101,176	77,595	44,147
Derivatives, net	17,180	71,885	(31,430)	59,968	48,021
(Gain) loss on equity method investments, net	—	—	(72,881)	6,252	—
Other expenses, net	37,802	24,648	(6,501)	5,291	23,116
Total costs and expenses	1,312,993	1,484,792	953,229	814,691	679,919
Income (loss) before income taxes	(416,795)	25,117	(50,860)	(177,855)	(294,564)
Income tax expense (benefit)	(5,209)	80,894	43,131	44,937	(10,784)
Net loss	$ (411,586)	$ (55,777)	$ (93,991)	$ (222,792)	$ (283,780)
Net loss per share:					
Basic	$ (1.02)	$ (0.14)	$ (0.23)	$ (0.57)	$ (0.74)
Diluted	$ (1.02)	$ (0.14)	$ (0.23)	$ (0.57)	$ (0.74)
Weighted average number of shares used to compute net loss per share:					
Basic	405,212	401,368	404,585	388,375	385,402
Diluted	405,212	401,368	404,585	388,375	385,402
Dividends declared per common share	$ 0.0452	$ 0.1808	$ —	$ —	$ —

Consolidated Balance Sheets Information:

	December 31,				
	2020	2019	2018	2017	2016
	(In thousands)				
Cash and cash equivalents	$ 149,027	$ 224,502	$ 173,515	$ 233,412	$ 194,057
Total current assets	400,291	566,557	509,700	533,602	475,187
Total property and equipment, net	3,320,913	3,642,332	3,459,701	2,317,828	2,708,892
Total other assets	146,389	108,343	118,788	341,173	157,386
Total assets	3,867,593	4,317,232	4,088,189	3,192,603	3,341,465
Total current liabilities	460,199	539,101	384,308	428,730	370,025
Total long-term liabilities	2,967,240	2,936,429	2,762,403	1,866,761	1,890,241
Total shareholders’ equity	440,154	841,702	941,478	897,112	1,081,199
Total liabilities and shareholders’ equity	3,867,593	4,317,232	4,088,189	3,192,603	3,341,465

Consolidated Statements of Cash Flows Information:

	Years Ended December 31,				
	2020	2019	2018	2017	2016
	(In thousands)				
Net cash provided by (used in):					
Operating activities	$ 196,145	$ 628,150	$ 260,491	$ 236,617	$ 52,077
Investing activities	(345,587)	(363,931)	(985,138)	(152,565)	(537,763)
Financing activities	69,860	(220,489)	605,277	(52,261)	448,019

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 the U.S. Gulf of Mexico, as well as a world-class gas development offshore Mauritania and Senegal. We also maintain a sustainable proven basin exploration program in Equatorial Guinea, Ghana and the U.S. Gulf of Mexico.

The ongoing COVID-19 pandemic that emerged at the beginning of 2020 has resulted in travel restrictions, including border closures, travel bans, social distancing restrictions and office closures being ordered in the various countries in which we operate, impacting some of our business operations. These ongoing restrictions have had an impact on the supply chain, resulting in the delay of various operational projects. Globally, the impact of COVID-19 has decreased demand for oil, which also resulted in significant declines in oil prices. The Company's revenues, earnings, cash flows, capital investments, debt capacity and, ultimately, future rate of growth are highly dependent on oil prices. Due to the COVID-19 pandemic, our operations have been impacted as follows:

- Delay to the installation of the Ghana Jubilee catenary anchor leg mooring ("CALM") buoy. The Government of Ghana implemented certain travel restrictions pertaining to its borders. The contractor responsible for the installation and commissioning of the Jubilee CALM buoy decided to suspend operations and demobilize from Ghana. The contractor returned to Ghana during the third quarter of 2020 to continue installation and commissioning of the CALM buoy. As a result of the delay, the Jubilee joint venture incurred approximately $6 million (gross) per month conducting ship to ship transfer operations until the CALM buoy was installed and commissioned in February 2021.

- Deferral of the planned 2020 Ghana drilling program associated with the termination of the Ghana drilling rig contract. The Company did not incur material costs associated with the termination of the drilling contract and is expected to resume drilling in the second quarter of 2021.

- Deferral of the completion operations on the Kodiak in-fill well drilled during 2020 in the U.S. Gulf of Mexico. Additionally, our U.S. Gulf of Mexico infrastructure led exploration (ILX) program was suspended. The Company did not incur material costs associated with the decision not to extend the drilling contract. In the fourth quarter of 2020, the Company re-commenced both the completion of the Kodiak in-fill well and our ILX program with the successful drilling of the Winterfell exploration well (formerly known as Monarch) in the U.S. Gulf of Mexico. See further discussion on both operations in U.S. Gulf of Mexico update below.

- Deferral of the 2020 Equatorial Guinea drilling program and ESP program. The Company did not incur material costs associated with the suspension of the programs and expects to restart in early 2021.

- Delay of the construction of the Greater Tortue Ahmeyim Phase 1 development project by approximately 12 months, with first gas now expected in the first half of 2023. Phase 1 of the project was approximately 50% complete as of year-end 2020. This delay resulted in a significant reduction in budgeted spend in 2020 as activity and milestone payments were delayed. With the re-phasing of the project timeline, the partnership approved a revised budget and, as a result, significantly reduced our capital expenditures in 2020.

- Government of Sao Tome and Principe implemented certain travel regulations restricting international travelers from entering the country. These restrictions made it impossible for the Company to safely manage the seismic acquisition in Blocks 10 and 13. As the technical operator of the seismic acquisition, the Company declared force majeure on the seismic acquisition contract and terminated it. Thereafter, BP, as operator of Blocks 10 and 13, declared force majeure on the blocks.

- Delayed expected spud date of the Jaca exploration well in Sao Tome and Principe Block 6 from the fourth quarter of 2020. The Company's interest in Sao Tome and Principe Block 6 was subsequently sold to Shell as discussed in Corporate update below.

- Suspension of the quarterly dividend by the Board of Directors.

- Reduced Company headcount resulting in restructuring charges for employee severance and related benefits totaling approximately $16.5 million during the year ended December 31, 2020.

- Recorded asset impairments totaling $154.0 million during the year ended December 31, 2020 primarily as a result of lower oil prices arising from the COVID-19 pandemic.

Recent Developments

Corporate

During the third quarter of 2020, Kosmos entered into an agreement with Shell to farm down interests in a portfolio of frontier exploration assets for cash consideration of $96.0 million and future contingent consideration of up to $100.0 million. Under the terms of the agreement, Shell acquired Kosmos' participating interest in blocks offshore Sao Tome and Principe (excluding Block 5 offshore Sao Tome and Principe), Suriname, and Namibia, and will acquire our participating interests in South Africa. Kosmos received proceeds totaling $95.0 million during the fourth quarter of 2020 resulting in gain on sale of assets of $92.1 million, with the remaining proceeds of $1.0 million related to Kosmos' participating interest in South Africa expected to be received in 2021 upon customary approval by the government of The Republic of South Africa. The future contingent consideration is based on the outcome of the first four wells drilled in the purchased assets, excluding South Africa, and is payable upon submission of an appraisal plan to the relevant governmental authority under the relevant host government contract. Shell will pay $50.0 million for each appraisal plan submitted, capped in the aggregate at a maximum of $100.0 million.

In June 2020, the Company received $50 million from Trafigura under a Production Prepayment Agreement of crude oil sales related to a portion of our U.S. Gulf of Mexico production primarily in 2022 and 2023. The Company terminated the Production Prepayment Agreement, and the initial prepayment of $50 million advanced under the Production Prepayment Agreement by Trafigura in the second quarter of 2020 has been extinguished and converted into the GoM Term Loan as of September 30, 2020. The GoM Term Loan is a five-year $200.0 million senior secured term-loan credit agreement secured against the Company's U.S. Gulf of Mexico assets. The GoM Term Loan also includes an accordion feature providing for incremental commitments of up to $100.0 million subject to certain conditions. The net proceeds were used to pay down a portion of the Facility and to fund U.S. Gulf of Mexico working capital and general operating expenses.

Ghana

During the year ended December 31, 2020, Ghana production averaged 131,800 Bopd gross (26,900 Bopd net). Ghana production was impacted as a result of the pause to our in-fill drilling program which is planned to restart in the second quarter of 2021. Jubilee production averaged approximately 83,100 Bopd gross (19,000 Bopd net) with consistent water injection and gas offtake since the work to enhance gas handling capacity was successfully performed by the operator during the first quarter of 2020. TEN production averaged approximately 48,700 Bopd gross (7,900 Bopd net) as the NT-09 producer well came online during the third quarter of 2020.

U.S. Gulf of Mexico

During the year ended December 31, 2020, U.S. Gulf of Mexico production averaged approximately 22,800 Boepd (net) (~81% oil).

In January 2020, we completed drilling the Oldfield exploration well. The well did not encounter commercial quantities of hydrocarbon and was plugged and abandoned.

As a result of market conditions in the second quarter, the operator of the Delta House platform in the U.S. Gulf of Mexico shut-in the facility during the month of May 2020 and accelerated planned maintenance. The shut-ins were primarily limited to May 2020 and all shut-in fields were brought back online by early June 2020.

In the first half of 2020, we successfully drilled a Kodiak development well located in Mississippi Canyon Block 727 (29.1% working interest). Due to the COVID-19 pandemic, the Company elected to defer the completion operations. During the fourth quarter of 2020, the Company re-commenced the Kodiak development well completion operations. The well is a subsea tieback, which is expected to be brought online through existing infrastructure to the Devils Tower SPAR in the first quarter of 2021.

In September 2020, the Tornado 4 water injector well located in Green Canyon Block 280 (35.0% working interest) commenced operations. The Tornado 4 water injector is providing pressure support for the field, increasing overall oil recovery.

In October 2020, the Company entered into a lease exchange agreement with affiliates of Ridgewood Energy Corporation in which Kosmos farmed down working interests in five blocks in exchange for a working interest in five additional blocks, including a 17.5 percent working interest in the drilling of the Winterfell (formerly known as Monarch) exploration prospect which was spud in the fourth quarter of 2020, re-commencing our ILX program in the U.S. Gulf of

Mexico. Winterfell was designed to test a sub-salt Upper Miocene prospect located in Green Canyon Block 944. In January 2021, we announced the well encountered approximately 26 meters (85 feet) of net oil pay in two intervals. We will now work with partners on an appraisal plan and development options for the discovery.

In the fourth quarter of 2020, the Company purchased additional acreage in 8 blocks in the U.S. Gulf of Mexico from BP for approximately $5.8 million and in a related transaction, sold a portion of the acreage to affiliates of Ridgewood Energy Corporation for approximately $2.4 million.

During the fourth quarter of 2020, the Company qualified for a suspension of federal royalties on oil production on four of our fields in the U.S. Gulf of Mexico, based on certain oil price thresholds. As a result, the Company recognized revenue of approximately $13.7 million in the fourth quarter of 2020 related to this federal royalty suspension for the year ended December 31, 2020.

Equatorial Guinea

Production in Equatorial Guinea averaged approximately 33,600 Bopd gross (11,100 Bopd net) for the year ended December 31, 2020.

In August 2020, we received approval for extensions to the current exploration phase for each of our four exploration blocks offshore Equatorial Guinea, Blocks S, W, 21, and 24.

Mauritania and Senegal

In October 2020, Kosmos withdrew from Block C6 offshore Mauritania.

Greater Tortue Ahmeyim Unit

The Tortue Phase 1 SPA was signed on February 11, 2020, resulting in approximately 100 MMBoe of proved undeveloped reserves being recognized at that time as evaluated by the Company's independent reserve auditor, Ryder Scott, LP. Due to the decrease in commodity prices during 2020 and the related commodity price utilized to calculate proved reserves for SEC purposes, the field did not have proved reserves recognition as of December 31, 2020. Phase 1 of the project is approximately 50% complete at year-end 2020 with first gas for the project expected in the first half of 2023.

Suriname

In July 2020, we provided notice that we declined to enter the final exploration phase of the Suriname Block 45 petroleum agreement.

Sao Tome and Principe

In the third quarter of 2020, we received approval for one year extensions to the current exploration phase for Block 5 offshore Sao Tome and Principe along with the elimination of the exploration well commitment from the current phase of Block 5.

Cote d'Ivoire

In May 2020, a withdrawal notice for our blocks offshore Cote d'Ivoire was issued to partners and the Government of Cote d'Ivoire.

Republic of the Congo

In February 2020, notice of withdrawal from the approval process awarding Kosmos' interest in the offshore Marine XXI block was issued to the Republic of the Congo.

The Republic of South Africa

In January 2021, a 2D seismic survey was acquired over Northern Cape Ultra Deep of approximately 500 line kilometers, fulfilling the current phase work commitment.

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 Equatorial Guinea, which was accounted for as an equity method investment during 2018. Certain operating results and statistics for the years ended December 31, 2020 and 2019 are included in the following tables. For a discussion of the year ended December 31, 2019 compared to the year ended December 31, 2018, please refer to Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2019.

	Years ended December 31,	
	2020	2019
	(In thousands, except per volume data)	
Sales volumes:		
Oil (MBbl)	20,531	23,331
Gas (MMcf)	5,867	6,323
NGL (MBbl)	602	548
Total (MBoe)	22,111	24,933
Total (Boepd)	60,412	68,309
Revenues:		
Oil sales	$ 786,159	$ 1,475,706
Gas sales	11,706	15,599
NGL sales	6,168	8,111
Total revenues	$ 804,033	$ 1,499,416
Average oil sales price per Bbl	$ 38.29	$ 63.25
Average gas sales price per Mcf	2.00	2.47
Average NGL sales price per Bbl	10.25	14.80
Average total sales price per Boe	36.36	60.14
Costs:		
Oil and gas production, excluding workovers	$ 336,662	$ 370,962
Oil and gas production, workovers	1,815	31,651
Total oil and gas production costs	$ 338,477	$ 402,613
Depletion, depreciation and amortization	$ 485,862	$ 563,861
Average cost per Boe:		
Oil and gas production, excluding workovers	$ 15.23	$ 14.88
Oil and gas production, workovers	0.08	1.27
Total oil and gas production costs	15.31	16.15
Depletion, depreciation and amortization	21.97	22.62
Total oil and gas production costs, depletion, depreciation and amortization	$ 37.28	$ 38.77

	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
Total (Boepd)		36,247		14,323		50,570
Revenues:						
Oil sales	$	874,382	$	360,649	$	1,235,031
Gas sales		7,101		—		7,101
NGL sales		5,183		—		5,183
Total revenues	$	886,666	$	360,649	$	1,247,315
Average oil sales price per Bbl	$	69.00	$	68.98	$	68.99
Average gas sales price per Mcf		3.13		—		3.13
Average NGL sales price per Bbl		28.96		—		28.96
Average total sales price per Boe		67.02		68.98		67.58
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, depreciation and amortization	$	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, depreciation and amortization		24.93		25.82		25.18
Total oil and gas production costs, depletion, depreciation and amortization	$	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, depreciation and amortization. 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.

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, 2020 vs. 2019

	Years Ended December 31,		Increase
	2020	2019	(Decrease)
		(In thousands)	
Revenues and other income:			
Oil and gas revenue	$ 804,033	$ 1,499,416	$ (695,383)
Gain on sale of assets	92,163	10,528	81,635
Other income, net	2	(35)	37
Total revenues and other income	896,198	1,509,909	(613,711)
Costs and expenses:			
Oil and gas production	338,477	402,613	(64,136)
Facilities insurance modifications, net	13,161	(24,254)	37,415
Exploration expenses	84,616	180,955	(96,339)
General and administrative	72,142	110,010	(37,868)
Depletion, depreciation and amortization	485,862	563,861	(77,999)
Impairment of long-lived assets	153,959	—	153,959
Interest and other financing costs, net	109,794	155,074	(45,280)
Derivatives, net	17,180	71,885	(54,705)
Other expenses, net	37,802	24,648	13,154
Total costs and expenses	1,312,993	1,484,792	(171,799)
Income (loss) before income taxes	(416,795)	25,117	(441,912)
Income tax expense (benefit)	(5,209)	80,894	(86,103)
Net loss	$ (411,586)	$ (55,777)	$ (355,809)

Oil and gas revenue. Oil and gas revenue decreased by $695.4 million as a result of lower production across our assets and lower oil prices stemming from the excess market supplies related to the COVID-19 pandemic. We sold 22,111 MBoe at an average realized price per barrel of oil equivalent of $36.36 in 2020 and 24,933 MBoe at an average realized price per barrel of oil equivalent of $60.14 in 2019.

Gain on sale of assets. In December 2020, we closed a farm-out agreement with Shell for a portfolio of frontier exploration assets in blocks offshore Sao Tome and Principe, Suriname, and Namibia. As part of the transaction, we received proceeds in excess of our book basis resulting in a gain of approximately $92.1 million. In November 2019, we closed a farm-out agreement with Shell for Blocks 6 and 11 offshore Sao Tome and Principe. As part of the transaction, we received proceeds in excess of our book basis resulting in a gain of $10.5 million.

Oil and gas production. Oil and gas production costs decreased by $64.1 million during the year ended December 31, 2020 as compared to the year ended December 31, 2019 as a result of cost reductions and lower workover costs in the current period.

Facilities insurance modifications, net. During the year ended December 31, 2020, we incurred $13.2 million of facilities insurance modification costs associated with the long-term solution to the Jubilee turret bearing issue versus $47.2 million during the year ended December 31, 2019. During the year ended December 31, 2020 and 2019, these costs were offset by zero hull and machinery insurance proceeds in 2020 and $71.5 million in 2019 as a result of final settlement of the insurance claim.

Exploration expenses. Exploration expenses decreased by $96.3 million during the year ended December 31, 2020, as compared to the year ended December 31, 2019. The decrease is primarily a result of lower unsuccessful well costs, geological, geophysical and seismic costs incurred in 2020 versus the prior period related to the U.S. Gulf of Mexico business unit.

General and administrative. General and administrative costs decreased by $37.9 million during the year ended December 31, 2020, as compared to the year ended December 31, 2019 primarily a result of lower headcount and other cost reductions.

Depletion, depreciation and amortization. Depletion, depreciation and amortization decreased $78.0 million during the year ended December 31, 2020, as compared with the year ended December 31, 2019 primarily as a result of lower sales volumes during the current period and a lower cost basis in the U.S. Gulf of Mexico associated with an impairment recorded in the first quarter of 2020.

Impairment of long-lived assets. As a result of the impact of COVID-19 on the demand for oil and the related significant decrease in oil prices, we recorded asset impairments totaling $154.0 million during the year ended December 31, 2020 for oil and gas proved properties in the U.S. Gulf of Mexico.

Interest and other financing costs, net. Interest and other financing costs, net decreased by $45.3 million primarily a result of no refinancing costs in 2020 as compared to the $24.8 million loss on extinguishment of debt primarily associated with the refinancing of our senior secured notes recorded during the second quarter of 2019 and lower interest rates during the current year as compared to the prior year.

Derivatives, net. During the years ended December 31, 2020 and 2019, we recorded a loss of $17.2 million and $71.9 million, respectively, on our outstanding hedge positions. The losses recorded were a result of changes in the forward curve of oil prices during the respective periods.

Other expenses, net. Other expenses, net increased $13.2 million primarily related to restructuring charges for employee severance and related benefit costs and inventory write downs.

Income tax expense (benefit). For the year ended December 31, 2020, our overall effective tax rate was impacted by: increases to our valuation allowance associated with our U.S. deferred tax assets; by the 35% statutory tax rates applicable to our Ghanaian and Equatorial Guinean operations; and by our exploration operations in tax-exempt jurisdictions or in taxable jurisdictions where we have valuation allowances against our deferred tax assets, and therefore, we do not realize any tax benefit on such losses or expenses.

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 exploration and production 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.

Current oil prices are volatile and could negatively impact our ability to generate sufficient operating cash flows to meet our funding requirements. This volatility could result in wide fluctuations in future oil prices, which could impact our ability to comply with our financial covenants. To partially mitigate this price volatility, we maintain an active hedging program and review our capital spending program on a regular basis. Our investment decisions are based on longer-term commodity prices based on the nature of our projects and development plans. Current commodity prices, combined with our hedging program, planned asset sales and our current liquidity position support our capital program for 2021.

As such, our 2021 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 the U.S. Gulf of Mexico, and our appraisal and development activities in Mauritania and Senegal.

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.

In April 2020, following the lenders' annual redetermination, the available borrowing base and Facility size were both reduced from $1.6 billion to approximately $1.5 billion. In addition, as part of the April 2020 redetermination process, the Company agreed to conduct an additional redetermination in September 2020. In October 2020, as a result of the September redetermination, the available borrowing base was reduced to approximately $1.32 billion and the Company agreed to conduct semi-annual redeterminations in March and September, beginning in 2021. The borrowing base calculation includes value related to the Jubilee, TEN, Ceiba and Okume fields.

In September 2020, the Company entered into a five-year $200.0 million senior secured term-loan credit agreement secured against the Company's U.S. Gulf of Mexico assets. The GoM Term Loan also includes an accordion feature providing for incremental commitments of up to $100.0 million subject to certain conditions.

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, 2020, 2019 and 2018:

	Years Ended December 31,		
	2020	2019	2018
	(In thousands)		
Sources of cash, cash equivalents and restricted cash:			
Net cash provided by operating activities	$ 196,145	$ 628,150	$ 260,491
Net proceeds from issuance of senior notes	—	641,875	—
Return of investment from KTIPI	—	—	184,664
Borrowings under long-term debt	300,000	175,000	1,175,000
Advances under production prepayment agreement	50,000	—	—
Proceeds on sale of assets	99,118	15,000	13,703
	645,263	1,460,025	1,633,858
Uses of cash, cash equivalents and restricted cash:			
Oil and gas assets	377,491	340,217	213,806
Other property	2,102	11,796	7,935
Acquisition of oil and gas properties	—	—	961,764
Notes receivable from partners	65,112	26,918	—
Payments on long-term debt	250,000	425,000	325,000
Redemption of senior secured notes	—	535,338	—
Purchase of treasury stock	4,947	1,983	206,051
Dividends	19,271	72,599	—
Deferred financing costs	5,922	2,444	38,672
	724,845	1,416,295	1,753,228
Increase (decrease) in cash, cash equivalents and restricted cash	$ (79,582)	$ 43,730	$ (119,370)

Net cash provided by operating activities. Net cash provided by operating activities in 2020 was $196.1 million compared with net cash provided by operating activities of $628.2 million in 2019 and $260.5 million in 2018, respectively. The decrease in cash provided by operating activities in the year ended December 31, 2020 when compared to the same period in 2019 is primarily a result of lower production across our assets and lower oil prices stemming from the excess market supplies related to the COVID-19 pandemic. The increase in cash provided by operating activities in the year ended December 31, 2019 when compared to the same period in 2018 is primarily a result of the inclusion of a full year of our U.S. Gulf of Mexico business unit during the year ended December 31, 2019 related to the DGE acquisition, which was completed during the third quarter of 2018. It is also the result of the inclusion of operations from Equatorial Guinea on a consolidated basis for the year ended December 31, 2019, which was previously accounted for as an equity method investment.

The following table presents our liquidity and financial position as of December 31, 2020:

		December 31, 2020
		(In thousands)
Cash and cash equivalents	$	149,027
Restricted cash		737
Senior Notes at par		650,000
Borrowings under the Facility		1,200,000
Borrowings under the Corporate Revolver		100,000
Borrowings under the GoM Term Loan		200,000
Net debt	$	2,000,236
Availability under the Facility	$	120,000
Availability under the Corporate Revolver	$	300,000
Available borrowings plus cash and cash equivalents	$	569,027

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; and
- execute appraisal, exploration and development activities in Mauritania and Senegal;

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, paying 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, health, 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 assets, 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.

2021 *Capital Program*

We estimate we will spend approximately $225 - $275 million of capital, excluding amounts related to Mauritania and Senegal, for the year ending December 31, 2021. This capital expenditure budget consists of:

- Approximately 80% related to exploitation and production optimization activities across our Ghana, Equatorial Guinea and U.S. Gulf of Mexico assets
- Approximately 20% related to our infrastructure-led exploration and development activities in the U.S. Gulf of Mexico

In Mauritania and Senegal we estimate capital expenditures of approximately $350 million based on our current ownership interest, excluding the impact of the planned Greater Tortue FPSO sale, which we estimate to be approximately $250 million. We expect to fund the remainder of this expenditure from working capital and proceeds from the refinancing of the Carry Advance Agreements with the national oil companies of Mauritania and Senegal.

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 infrastructure-led 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

The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities with a borrowing base calculation that includes value related to the Jubilee, TEN, Ceiba and Okume fields. 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 taking total commitments to $1.6 billion. 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. The commitments were reduced by $100.0 million to $1.6 billion following the Senior Notes issuance in April 2019. In April 2020, following the lenders' annual redetermination, the available borrowing base and Facility size were both reduced from $1.6 billion to approximately $1.5 billion. In addition, as part of the April 2020 redetermination process, the Company agreed to conduct an additional redetermination in September 2020. As a result, in October 2020, the available borrowing base was reduced to approximately $1.32 billion. The Company made repayments totaling $250 million during the fourth quarter of 2020. Additionally, the Company agreed to conduct semi-annual redeterminations every March and September, beginning with March 2021. When our net leverage ratio exceeds 2.50x, we are required under the Facility to maintain a restricted cash balance that is sufficient to meet the payment of interest and fees for the next six-month period on the 7.125% Senior Notes plus the Corporate Revolver or the Facility, whichever is greater. As of December 31, 2020, we exceeded this ratio and restricted approximately $28.5 million in cash to meet our requirements in January 2021.

As of December 31, 2020, borrowings under the Facility totaled $1.2 billion and the undrawn availability under the Facility was $120.0 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 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, 2020, 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. In October 2020, the Company agreed to conduct semi-annual redeterminations every March and September, beginning with March 2021. 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 below contained in the Facility as of September 30, 2020 (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 interest cover ratio (as defined in the glossary), not less than 2.25x.
- the debt cover ratio (as defined in the glossary), amended as described below:

As result of the impact of COVID-19 on the demand for oil and the related significant decrease in oil prices, our ability to comply with one of our financial covenants, the debt cover ratio, may be impacted in future periods. Therefore, in July 2020, we proactively worked with our lender group, prior to any inability to comply with the financial covenants thereunder, to amend the debt cover ratio calculation through December 31, 2021. The amendment makes this covenant less restrictive during the stated period up to a maximum of 4.75x and thereafter gradually returns to the originally agreed upon ratio of 3.5x. The Facility contains customary cross default provisions.

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 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.

As of December 31, 2020, there were $100.0 million in outstanding borrowings under the Corporate Revolver and the undrawn availability under the Corporate Revolver was $300.0 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 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.

We were in compliance with the financial covenants below contained in the Corporate Revolver as of September 30, 2020 (the most recent assessment date), which requires the maintenance of:

- the interest cover ratio (as defined in the glossary), not less than 2.25x.
- the debt cover ratio (as defined in the glossary), amended as described below:

As result of the impact of COVID-19 on the demand for oil and the related significant decrease in oil prices, our ability to comply with one of our financial covenants, the debt cover ratio, may be impacted in future periods. Therefore, in July 2020, we proactively worked with our lender group, prior to any inability to comply with the financial covenants thereunder, to amend the debt cover ratio calculation through December 31, 2021. The amendment makes this covenant less restrictive during the stated period up to a maximum of 4.75x and thereafter gradually returns to the originally agreed upon ratio of 3.5x. The Corporate Revolver contains customary cross default provisions.

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.

7.875% Senior Secured Notes due 2021

In April 2019, all of the Senior Secured Notes were redeemed for $543.8 million, including accrued interest and the early redemption premium. The redemption resulted in a $22.9 million loss on extinguishment of debt, which is included in Interest and other financing costs, net on the consolidated statement of operations.

7.125% Senior Notes due 2026

In April 2019, the Company issued $650.0 million of 7.125% Senior Notes and received net proceeds of approximately $640.0 million after deducting commissions and other expenses. We used the net proceeds to redeem all of the Senior Secured Notes, repay a portion of the outstanding indebtedness under the Corporate Revolver and pay fees and expenses related to the redemption, repayment and the issuance of the Senior Notes.

The Senior Notes mature on April 4, 2026. We will pay interest in arrears on the Senior Notes each April 4 and October 4, commencing on October 4, 2019. The Senior Notes are senior, unsecured obligations of Kosmos Energy Ltd. and rank equal in right of payment with all of its existing and future senior indebtedness (including all borrowings under the Corporate Revolver) and rank effectively junior in right of payment to all of its existing and future secured indebtedness (including all borrowings under the Facility). The Senior Notes are guaranteed on a senior, unsecured basis by certain subsidiaries owning the Company's U.S. Gulf of Mexico assets, and on a subordinated, unsecured basis by certain subsidiaries that guarantee the Facility.

At any time prior to April 4, 2022, and subject to certain conditions, the Company may, on one or more occasions, redeem up to 40% of the original principal amount of the Senior Notes with an amount not to exceed the net cash proceeds of certain equity offerings at a redemption price of 107.1% of the outstanding principal amount of the Senior Notes, together with accrued and unpaid interest and premium, if any, to, but excluding, the date of redemption. Additionally, at any time prior to April 4, 2022 the Company may, on any one or more occasions, redeem all or a part of the Senior Notes at a redemption price equal to 100%, plus any accrued and unpaid interest, and plus a "make-whole" premium. On or after April 4, 2022, 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 April 4, 2022, but before April 4, 2023	103.6 %
On or after April 4, 2023, but before April 4, 2024	101.8 %
On or after April 4, 2024 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 Senior Notes 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 Senior Notes 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.

The Senior Notes 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.

Production Prepayment Agreement, net

In June 2020, the Company received $50 million from Trafigura under a Production Prepayment Agreement of crude oil sales related to a portion of our U.S. Gulf of Mexico production primarily in 2022 and 2023. The Company has terminated the Production Prepayment Agreement and the initial prepayment of $50 million advanced under the Production Prepayment Agreement by Trafigura in the second quarter of 2020 has been extinguished and converted into the GoM Term Loan as of September 30, 2020.

GoM Term Loan

In September 2020, the Company entered into a five-year $200 million senior secured term-loan credit agreement secured against the Company's U.S. Gulf of Mexico assets with net proceeds received of $197.7 million after deducting fees and other expenses. The GoM Term Loan also includes an accordion feature providing for incremental commitments of up to $100 million subject to certain conditions. The net proceeds will be used to pay down a portion of the Facility and to fund U.S. Gulf of Mexico working capital and general operating expenses. The $50 million advanced under the Production Prepayment Agreement with Trafigura in the second quarter of 2020 has been extinguished and converted as part of the GoM Term Loan with the remaining $150 million provided by an affiliate of Beal Bank. The GoM Term Loan bears interest at an effective rate of approximately 6% per annum and matures in 2025, with principal repayments beginning in the fourth quarter of 2021.

The GoM Term Loan contains customary affirmative and negative covenants, including covenants that affect our ability to incur additional indebtedness, create liens, merge, dispose of assets, and make distributions, dividends, investments or capital expenditures, among other things. The GoM Term Loan is guaranteed on a senior, secured basis by certain subsidiaries owning the Company's U.S. Gulf of Mexico assets.

The GoM Term Loan includes certain representations and warranties, indemnities and events of default that, subject to certain materiality thresholds and grace periods, arise as a result of a payment default, failure to comply with covenants, material inaccuracy of representation or warranty, and certain bankruptcy or insolvency proceedings. If there is an event of default, all or any portion of the outstanding indebtedness may be immediately due and payable and other rights may be exercised including against the collateral.

Contractual Obligations

The following table summarizes by period the payments due for our estimated contractual obligations as of December 31, 2020:

	Payments Due By Year(4)						
	Total	**2021**	**2022**	**2023**	**2024**	**2025**	**Thereafter**
	(In thousands)						
Principal debt repayments(1)	$ 2,150,000	$ 7,500	$ 258,571	$ 458,571	$ 458,572	$ 316,786	$ 650,000
Interest payments on long-term debt(2)	466,436	113,603	108,561	91,972	75,364	53,780	23,156
Operating leases(3)	36,067	3,307	4,216	4,287	4,358	4,429	15,470

(1) Includes the scheduled maturities for the $650.0 million aggregate principal amount of Senior Notes and borrowings under the Facility, Corporate Revolver and GoM Term Loan. The scheduled maturities of debt related to the Facility are based on, as of December 31, 2020, 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 or benchmark rate 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 two exploration wells and approximately 1,000 square kilometer 3D seismic acquisition requirement in Mauritania. In South Africa, as of December 31, 2020, we had 2D seismic acquisition requirements of approximately 500 line kilometers, which was acquired in January 2021.

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.

The following table presents maturities by expected debt maturity dates, the weighted-average interest rates expected to be paid on the Facility, Corporate Revolver and GoM Term Loan given current contractual terms and market conditions, and the instrument'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,
	2021	2022	2023	2024	2025	Thereafter	2020
	(In thousands, except percentages)						
Fixed rate debt:							
Senior Notes	$ —	$ —	$ —	$ —	$ —	$ 650,000	$ (613,412)
Fixed interest rate	7.13 %	7.13 %	7.13 %	7.13 %	7.13 %	7.13 %	
Variable rate debt:							
Facility(1)	$ —	$ 128,571	$ 428,571	$ 428,572	$ 214,286	$ —	$ (1,200,000)
Corporate Revolver	—	100,000	—	—	—	—	(100,000)
GoM Term Loan	7,500	30,000	30,000	30,000	102,500	—	(200,000)
Weighted average interest rate(2)	3.98 %	4.20 %	4.47 %	5.20 %	5.90 %	— %	

(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, 2020. 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 or benchmark rate 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, 2020, our off-balance sheet arrangements and transactions include short-term operating leases and undrawn letters of credit. There are no other transactions, arrangements, or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect Kosmos' liquidity or availability of or requirements for capital resources.

Critical Accounting Policies

This discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements, which have been prepared in accordance with generally accepted accounting principles in the United States. The preparation of our financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities as of the date the financial statements are available to be issued. These estimates could change materially if different information or assumptions were used. 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 recognize revenues on the volumes of hydrocarbons sold to a purchaser. 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, 2020 and 2019, we had no oil and gas imbalances recorded in our consolidated financial statements.

Our oil and gas revenues are recognized when hydrocarbons have been sold to a purchaser at a fixed or determinable price, title has transferred and collection 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.

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 expensed as incurred. Exploratory drilling costs are capitalized when incurred. If exploratory wells are determined to be commercially unsuccessful or dry holes, the applicable costs are expensed and recorded in exploration expense on the consolidated statement of operations. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized. Costs incurred to operate and maintain wells and equipment and to lift oil and natural gas to the surface are expensed as oil and gas production expense.

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. As required by ASU 2016-13, "Measurement of Credit Losses on Financial Instruments", we determine our allowance based on historical experience, current conditions and reasonable and supportable forecasts 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, 2020 and 2019, 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 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 a liabilities and are measured at fair value. We do not apply hedge accounting to our 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 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 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 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, depreciation and amortization 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. 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. Oil and gas properties are grouped in accordance with ASC 932 — Extractive Activities-Oil and Gas. The basis for grouping is a reasonable aggregation of properties typically by field or by logical grouping of assets with significant shared infrastructure.

For long-lived assets whereby the carrying value exceeds the estimated future undiscounted cash flows, the carrying amount is reduced to fair value. Fair value is generally estimated using the income approach described in the ASC 820 — Fair Value Measurement. If applicable, we utilize prices and other relevant information generated by market transactions involving assets and liabilities that are identical or comparable to the item being measured as the basis for determining fair value. The expected future cash flows used for impairment reviews and related fair value measurements are typically based on judgmental assessments of future production, pricing estimates, capital and operating costs, market-based weighted average cost of capital, and risk adjustment factors applied to reserves. These assumptions are applied to develop future cash flow projections that are then discounted to estimated fair value, using a market-based weighted-average cost of capital. Although we base the fair value estimate of each asset group on assumptions we believe to be reasonable, those assumptions are inherently unpredictable and uncertain, and actual results could differ from the estimate. Negative revisions of estimated reserve quantities, increases in future cost estimates, divestiture of a significant component of the asset group, or sustained decreases in crude oil prices could lead to a reduction in expected future cash flows and possibly an additional impairment of long-lived assets in future periods.

We believe the assumptions used in our analysis to test for impairment are appropriate and result in a reasonable estimate of future cash flows and fair value. Kosmos has consistently used an average of third-party industry forecasts to determine our pricing assumptions. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the evaluation.

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

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

New Accounting Pronouncements

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

Item 7A. Qualitative and Quantitative Disclosures About Market Risk

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

We manage market and counterparty credit risk in accordance with our policies. In accordance with these policies and guidelines, our management determines the appropriate timing and extent of derivative transactions. See "Item 8. Financial Statements and Supplementary Data—Note 2—Accounting Policies, Note 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, 2020:

	Derivative Contracts Assets (Liabilities) Commodities (In thousands)
Fair value of contracts outstanding as of December 31, 2019	$ (8,521)
Changes in contract fair value	(22,800)
Contract maturities	10,944
Fair value of contracts outstanding as of December 31, 2020	$ (20,377)

Commodity Price Risk

The ongoing COVID-19 pandemic that emerged at the beginning of 2020 has resulted in travel restrictions, including border closures, travel bans, social distancing restrictions and office closures being ordered in the various countries in which we operate, impacting some of our business operations. These ongoing restrictions have had an impact on the supply chain, resulting in the delay of various operational projects. Globally, the impact of COVID-19 has decreased demand for oil, which also resulted in significant declines in oil prices. 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 and Heavy Louisiana Sweet. Oil prices during 2020 ranged between $13.24 and $69.96 per Bbl for Dated Brent, with Heavy Louisiana Sweet experiencing similar volatility during 2020.

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. In addition, a reduction in our ability to access credit could reduce our ability to implement derivative contracts on commercially reasonable terms.

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, 2020:

				Weighted Average Price per Bbl					
Term	Type of Contract	Index	MBbl	Net Deferred Premium Payable/(Receivable)	Swap	Sold Put	Floor	Ceiling	Asset (Liability) Fair Value at December 31, 2020(2)
2021									(In thousands)
January — December	Swaps with sold puts	Dated Brent	6,000	$ —	$ 53.96	$ 42.92	$ —	$ —	$ 4,084
January — June	Swaps with sold puts	NYMEX WTI	1,000	—	47.75	37.50	—	—	(1,351)
January — December	Three-way collars	Dated Brent	4,000	0.34	—	33.13	40.63	52.60	(12,380)
January — December	Three-way collars	NYMEX WTI	1,000	1.00	—	37.50	45.00	55.00	(1,291)
January — December	Sold calls(1)	Dated Brent	7,000	—	—	—	—	70.09	(3,658)
2022									
January — December	Sold calls(1)	Dated Brent	1,581	—	—	—	—	60.00	(5,103)

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

(2) Fair values are based on the average forward oil prices on December 31, 2020.

In February 2021, we entered into Dated Brent three-way collar contracts for 1.5 MMBbl from January 2022 through December 2022 with a sold put price of $40.00 per barrel, a floor price of $50.00 per barrel and a ceiling price of $70.00 per barrel.

At December 31, 2020, our open commodity derivative instruments were in a net liability position of $19.7 million. As of December 31, 2020, a hypothetical 10% price increase in the commodity futures price curves would decrease future pre-tax earnings by approximately $54.2 million. Similarly, a hypothetical 10% price decrease would increase future pre-tax earnings by approximately $44.1 million.

Interest Rate Sensitivity

Changes in market interest rates affect the amount of interest we pay on certain of our borrowings. Outstanding borrowings under the Facility, Corporate Revolver and GoM Term Loan, which as of December 31, 2020 total $1.5 billion and have a weighted average interest rate of 4.2%, are subject to variable interest rates, which expose us to the risk of earnings or cash flow loss due to potential increases in market interest rates. If the floating market rate increased 10% at this level of floating rate debt, we would pay an estimated additional $0.4 million interest expense per year. The commitment fees on the undrawn availability under the Facility and the Corporate Revolver are not subject to changes in interest rates. All of our other long-term indebtedness is fixed rate and does not expose us to the risk of cash flow loss due to changes in market interest rates. Additionally, a change in the market interest rates could impact interest costs associated with future debt issuances or any future borrowings.

Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2020 and 2019, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2020, 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 as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, 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, 2020, 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 23, 2021 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 include 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.

Critical audit matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Depletion of proved oil and natural gas properties

Description of the Matter	At December 31, 2020, the net book value of the Company's proved oil and natural gas properties was $2.815 billion, and depletion expense was $460.9 million for the year then ended. As described in Note 2, the Company follows the successful efforts method of accounting for its oil and natural gas properties. 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 depleted using the unit-of-production method based on estimated proved developed oil and natural gas reserves for the related field. The Company's oil and natural gas reserves are estimated by independent reserve engineers. 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. Significant judgment is required by the Company's independent reserve engineers in evaluating geological and engineering data when estimating proved oil and natural gas reserves. Estimating reserves also requires the selection of inputs, including oil and natural gas price assumptions and future operating and capital cost assumptions, among others. Because of the complexity involved in estimating oil and natural gas reserves, management used independent reserve engineers to prepare the estimate of reserve quantities as of December 31, 2020.
	Auditing the Company's depletion calculation is complex because of the use of the work of independent reserve engineers and the evaluation of management's determination of the inputs described above used by the independent reserve engineers in estimating proved oil and natural gas reserves.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of the controls over the Company's process to calculate depletion, including management's controls over the completeness and accuracy of the financial data and inputs provided to the independent reserve engineers for use in estimating the proved oil and natural gas reserves.
	Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the independent reserve engineers used to prepare the estimate of proved oil and natural gas reserves. Additionally, in assessing whether we can use the work of the independent reserve engineers we evaluated the completeness and accuracy of the financial data and inputs described above used by the independent reserve engineers in estimating proved oil and natural gas reserves by agreeing them to source documentation and we identified and evaluated corroborative and contrary evidence. For proved undeveloped reserves, we evaluated management's development plan for compliance with the Securities and Exchange Commission rule that undrilled locations are scheduled to be drilled within five years, unless specific circumstances justify a longer time, by assessing consistency of the development projections with the Company's drill plan and the availability of capital relative to the drill plan. We also tested the mathematical accuracy of the depletion calculations, including comparing the estimated proved oil and natural gas reserve amounts used to the Company's reserve report.

Asset Retirement Obligations

Description of the Matter

At December 31, 2020, the Company's asset retirement obligations totaled $251.4 million. As described in Note 2, 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 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.

Auditing the Company's asset retirement obligations was complex and highly judgmental due to the significant estimation required by management to determine the estimated present value of the amount of dismantlement, removal, site reclamation and similar activities associated with the Company's oil and natural gas properties. In particular, the estimate was sensitive to significant assumptions such as the expected cash outflows for retirement obligations and the ultimate productive life of the properties.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design and tested the operating effectiveness of the controls over the Company's process to estimate asset retirement obligations, including controls over management's review of the significant assumptions described above.

Our audit procedures included, among others, testing the significant assumptions discussed above and the underlying data used by the Company. For example, we evaluated expected cash outflows for asset retirement obligations by comparing to recent offshore activities and costs. We also compared the ultimate productive life of the properties to forecasts of production based on estimates of proved oil and natural gas reserves, as estimated by independent reserve engineers. We involved our specialists to assist in our evaluation of the expected cash flows for retirement obligations.

Impairment of long-lived assets

Description of the Matter

As described in Note 10 to the consolidated financial statements, the Company recorded an impairment of $150.8 million during the year ended December 31, 2020 related to certain oil and gas proved properties. The impact of COVID-19 on the demand for oil and the significant decrease in oil prices during the first quarter of 2020 triggered an assessment of these long-lived assets for impairment. The Company evaluated their proved property asset groups for recoverability and determined certain asset groups in the U.S. Gulf of Mexico had carrying values that were not recoverable through the estimated undiscounted future net cash flows. As a result, the Company recognized an impairment, which is the amount by which the asset group's carrying value exceeded its estimated fair value.

Auditing the Company's expected future cash flows used to measure impairment was complex and judgmental as the determination of fair value was based on future production, pricing estimates, capital and operating costs, market-based weighted average cost of capital, and risk adjustment factors.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design, and tested the operating effectiveness of controls over the Company's process to determine the fair value of the asset group and measure the impairment. This included controls over management's review of the significant assumptions underlying the fair value determination and of the completeness and accuracy of the data used in the determination of the fair value.

Our audit procedures included, among others, evaluating the significant assumptions and testing the completeness and accuracy of underlying data used in the calculation of the fair value, including identifying corroborative and contrary evidence, performing sensitivity analyses of the significant assumptions to evaluate the change in the fair value estimate that would result from changes in the assumptions and recalculating management's estimate. We involved valuation specialists to assist in our evaluation of the valuation methodologies applied and the significant assumptions used to determine the fair value of the asset group, including the discount rate, risk adjustment factors, forward looking commodity prices and future operating and capital cost assumptions.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2004.
Dallas, Texas
February 23, 2021

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, 2020, 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, 2020, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2020 and 2019, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2020, and the related notes and financial statement schedules listed in the Index at Item 15(a) and our report dated February 23, 2021 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 23, 2021

KOSMOS ENERGY LTD.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	December 31, 2020	December 31, 2019
Assets		
Current assets:		
Cash and cash equivalents	$ 149,027	$ 224,502
Restricted cash	195	4,302
Receivables:		
Joint interest billings, net	26,002	81,424
Oil sales	44,491	64,142
Other	8,320	28,727
Inventories	128,972	114,412
Prepaid expenses and other	27,870	36,192
Derivatives	15,414	12,856
Total current assets	400,291	566,557
Property and equipment:		
Oil and gas properties, net	3,310,276	3,624,751
Other property, net	10,637	17,581
Property and equipment, net	3,320,913	3,642,332
Other assets:		
Restricted cash	542	542
Long-term receivables	117,497	43,430
Deferred financing costs, net of accumulated amortization of $17,296 and $14,681 at December 31, 2020 and December 31, 2019, respectively	3,706	6,321
Deferred tax assets	—	32,779
Derivatives	964	2,302
Other	23,680	22,969
Total assets	$ 3,867,593	$ 4,317,232
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable	$ 221,430	$ 149,483
Accrued liabilities	203,260	380,704
Current maturities of long-term debt	7,500	—
Derivatives	28,009	8,914
Total current liabilities	460,199	539,101
Long-term liabilities:		
Long-term debt, net	2,103,931	2,008,063
Derivatives	8,069	11,478
Asset retirement obligations	244,166	230,526
Deferred tax liabilities	573,619	653,221
Other long-term liabilities	37,455	33,141
Total long-term liabilities	2,967,240	2,936,429
Stockholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2020 and December 31, 2019	—	—
Common stock, $0.01 par value; 2,000,000,000 authorized shares; 449,718,317 and 445,779,367 issued at December 31, 2020 and December 31, 2019, respectively	4,497	4,458
Additional paid-in capital	2,307,220	2,297,221
Accumulated deficit	(1,634,556)	(1,222,970)
Treasury stock, at cost, 44,263,269 shares at December 31, 2020 and December 31, 2019, respectively	(237,007)	(237,007)
Total stockholders' equity	440,154	841,702
Total liabilities and stockholders' equity	$ 3,867,593	$ 4,317,232

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	Years Ended December 31, 2020	2019	2018
Revenues and other income:			
Oil and gas revenue	$ 804,033	$ 1,499,416	$ 886,666
Gain on sale of assets	92,163	10,528	7,666
Other income, net	2	(35)	8,037
Total revenues and other income	896,198	1,509,909	902,369
Costs and expenses:			
Oil and gas production	338,477	402,613	224,727
Facilities insurance modifications, net	13,161	(24,254)	6,955
Exploration expenses	84,616	180,955	301,492
General and administrative	72,142	110,010	99,856
Depletion, depreciation and amortization	485,862	563,861	329,835
Impairment of long-lived assets	153,959	—	—
Interest and other financing costs, net	109,794	155,074	101,176
Derivatives, net	17,180	71,885	(31,430)
Gain on equity method investments, net	—	—	(72,881)
Other expenses, net	37,802	24,648	(6,501)
Total costs and expenses	1,312,993	1,484,792	953,229
Income (loss) before income taxes	(416,795)	25,117	(50,860)
Income tax expense (benefit)	(5,209)	80,894	43,131
Net loss	$ (411,586)	$ (55,777)	$ (93,991)
Net loss per share:			
Basic	$ (1.02)	$ (0.14)	$ (0.23)
Diluted	$ (1.02)	$ (0.14)	$ (0.23)
Weighted average number of shares used to compute net loss per share:			
Basic	405,212	401,368	404,585
Diluted	405,212	401,368	404,585
Dividends declared per common share	$ 0.0452	$ 0.1808	$ —

See accompanying notes.

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, 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 / tax withholdings	—	—	(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
Dividends ($0.1808 per share)	—	—	(74,813)	—	—	(74,813)
Equity-based compensation	—	—	32,797	—	—	32,797
Restricted stock awards and units	2,864	29	(29)	—	—	—
Purchase of treasury stock / tax withholdings	—	—	(1,983)	—	—	(1,983)
Net loss	—	—	—	(55,777)	—	(55,777)
Balance as of December 31, 2019	445,779	4,458	2,297,221	(1,222,970)	(237,007)	841,702
Dividends ($0.0452 per share)	—	—	(18,576)	—	—	(18,576)
Equity-based compensation	—	—	33,561	—	—	33,561
Restricted stock awards and units	3,939	39	(39)	—	—	—
Purchase of treasury stock / tax withholdings	—	—	(4,947)	—	—	(4,947)
Net loss	—	—	—	(411,586)	—	(411,586)
Balance as of December 31, 2020	449,718	$ 4,497	$ 2,307,220	$ (1,634,556)	$ (237,007)	$ 440,154

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31, 2020	2019	2018
Operating activities			
Net loss	$ (411,586)	$ (55,777)	$ (93,991)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depletion, depreciation and amortization (including deferred financing costs)	495,209	573,118	339,214
Deferred income taxes	(42,587)	(90,370)	9,145
Unsuccessful well costs and leasehold impairments	23,157	87,813	123,199
Impairment of long-lived assets	153,959	—	—
Change in fair value of derivatives	22,800	67,436	(29,960)
Cash settlements on derivatives, net (including $(2.7) million and $(36.3) million and $(137.1) million on commodity hedges during 2020, 2019, and 2018)	(10,944)	(31,458)	(137,942)
Equity-based compensation	32,706	32,370	35,230
Gain on sale of assets	(92,163)	(10,528)	(7,666)
Loss on extinguishment of debt	2,902	24,794	4,324
Other	15,922	9,069	2,820
Changes in assets and liabilities:			
(Increase) decrease in receivables	92,093	(29,735)	175,954
(Increase) decrease in inventories	(23,167)	(28,970)	8,848
(Increase) decrease in prepaid expenses and other	7,882	34,586	(18,731)
Increase (decrease) in accounts payable	71,947	(83,921)	7,440
Increase (decrease) in accrued liabilities	(141,985)	129,723	(157,393)
Net cash provided by operating activities	196,145	628,150	260,491
Investing activities			
Oil and gas assets	(377,491)	(340,217)	(213,806)
Other property	(2,102)	(11,796)	(7,935)
Acquisition of oil and gas properties, net of cash acquired	—	—	(961,764)
Return of investment from KTIPI	—	—	184,664
Proceeds on sale of assets	99,118	15,000	13,703
Notes receivable from partners	(65,112)	(26,918)	—
Net cash used in investing activities	(345,587)	(363,931)	(985,138)
Financing activities			
Borrowings under long-term debt	300,000	175,000	1,175,000
Payments on long-term debt	(250,000)	(425,000)	(325,000)
Advances under production prepayment agreement	50,000	—	—
Net proceeds from issuance of senior notes	—	641,875	—
Redemption of senior secured notes	—	(535,338)	—
Purchase of treasury stock / tax withholdings	(4,947)	(1,983)	(206,051)
Dividends	(19,271)	(72,599)	—
Deferred financing costs	(5,922)	(2,444)	(38,672)
Net cash provided by (used in) financing activities	69,860	(220,489)	605,277
Net increase (decrease) in cash, cash equivalents and restricted cash	(79,582)	43,730	(119,370)
Cash, cash equivalents and restricted cash at beginning of period	229,346	185,616	304,986
Cash, cash equivalents and restricted cash at end of period	$ 149,764	$ 229,346	$ 185,616
Supplemental cash flow information			
Cash paid for:			
Interest, net of capitalized interest	$ 103,674	$ 99,928	$ 83,831
Income taxes, net of refund received	$ 104,061	$ 43,909	$ 45,984
Non-cash activity:			
Production Prepayment Agreement converted to GoM Term Loan	$ 50,000	$ —	$ —
Common stock issued for acquisition of oil and gas properties	$ —	$ —	$ 307,944

See accompanying notes.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements

1. Organization

Kosmos Energy Ltd. was originally incorporated pursuant to the laws of Bermuda in January 2011 to become a holding company for Kosmos Energy Holdings. Kosmos Energy Ltd. changed its jurisdiction of incorporation from Bermuda to the State of Delaware in December 2018 and 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 the U.S. Gulf of Mexico, as well as a world-class gas development offshore Mauritania and Senegal. We also maintain a sustainable proven basin exploration program in Equatorial Guinea, Ghana and the U.S. Gulf of Mexico. Kosmos is listed on the NYSE and LSE and is traded under the ticker symbol KOS.

Kosmos is engaged in a single line of business, which is the exploration, development, and production of oil and natural gas. Substantially all of our long-lived assets and all of our product sales are related to operations in four geographic areas: Ghana, Equatorial Guinea, Mauritania/Senegal and the U.S. Gulf of Mexico.

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. These estimates could change materially if different information or assumptions were used. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. 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 significant impact on our reported net loss, current assets, total assets, current liabilities, total liabilities, shareholders' equity or cash flows, except as disclosed related to the adoption of recent accounting pronouncements.

Cash, Cash Equivalents and Restricted Cash

	December 31,		
	2020	2019	2018
	(In thousands)		
Cash and cash equivalents	$ 149,027	$ 224,502	$ 173,515
Restricted cash - current	195	4,302	4,527
Restricted cash - long-term	542	542	7,574
Total cash, cash equivalents and restricted cash shown in the consolidated statements of cash flows	$ 149,764	$ 229,346	$ 185,616

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. When our net leverage ratio exceeds 2.50x, we are required under the Facility to maintain a restricted cash balance that is sufficient to meet the payment of interest and fees for the next six-month period on the 7.125% Senior Notes plus the Corporate Revolver or the Facility, whichever is greater. As of December 31, 2020, we exceeded this ratio and restricted approximately $28.5 million in cash to meet our requirements in January 2021.

In accordance with certain of our petroleum contracts, we have posted letters of credit related to performance guarantees for our minimum work obligations. Certain of 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, 2020 and 2019, we had $0.2 million and $4.3 million, respectively, of current restricted cash and $0.3 million and $0.3 million, respectively, of long-term restricted cash used to cash collateralize performance guarantees related to our petroleum contracts. As of December 31, 2020 and 2019, we also had $0.2 million in other long-term restricted cash.

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. As required by ASU 2016-13, "Measurement of Credit Losses on Financial Instruments", we determine our allowance based on historical experience, current conditions and reasonable and supportable forecasts 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 $5.7 million and $2.7 million in current joint interest billings receivables as of December 31, 2020 and 2019, respectively.

Inventories

Inventories consisted of $127.5 million and $112.3 million of materials and supplies and $1.5 million and $2.1 million of hydrocarbons as of December 31, 2020 and 2019, 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 $8.6 million, $4.6 million and $0.3 million during the years ended December 31, 2020, 2019 and 2018 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.

Leases

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 prior accounting guidance, lessees did not recognize lease assets or liabilities for leases classified as operating leases. The ASU was 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 adopted the guidance prospectively during the first quarter of 2019. As part of our adoption, we elected not to reassess historical lease classification, recognize short-term leases on our balance sheet, nor separate lease and non-lease components for our real estate leases. The adoption and implementation of this ASU resulted in a $21.7 million increase in assets and liabilities related to our leasing activities, which primarily consists of office leases. Our adoption of ASU 2016-02 did not impact retained earnings or other components of equity as of December 31, 2018.

We account for leases in accordance with ASC Topic 842, Leases, (“ASC 842”). We determine if an arrangement is a lease at contract inception. A lease exists when a contract conveys to the customer the right to control the use of identified property, plant, or equipment for a period of time in exchange for consideration. The definition of a lease embodies two conditions: (1) there is an identified asset in the contract that is land or a depreciable asset (i.e., property, plant, and equipment), and (2) the customer has the right to control the use of the identified asset.

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. Operating leases are included in Other assets, Accrued liabilities, and Other long-term liabilities on our consolidated balance sheets. The lease liabilities are initially and subsequently measured at the present value of the unpaid lease payments at the lease commencement date.

Key estimates and judgments include how we determined: (1) the discount rate we use to discount the unpaid lease payments to present value; (2) lease term; and (3) lease payments.

1. ASC 842 requires a lessee to discount its unpaid lease payments using the interest rate implicit in the lease or, if that rate cannot be readily determined, its incremental borrowing rate. As most of our leases where we are the lessee do not provide an implicit rate, we use our incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. Our incremental borrowing rate for a lease is the rate of interest we would have to pay on a collateralized basis to borrow an amount equal to the lease payments under similar terms.

2. The lease term for all of our leases includes the non-cancellable period of the lease plus any additional periods covered by either an option to extend (or not to terminate) the lease that we are reasonably certain to exercise, or an option to extend (or not to terminate) the lease controlled by the lessor.

3. Lease payments included in the measurement of the lease asset or liability comprise the following: fixed payments (including in-substance fixed payments), variable payments that depend on index or rate, and the exercise price of a lessee option to purchase the underlying asset if we are reasonably certain to exercise. Amounts expected to be payable under residual value guarantee are also lease payments included in the measurement of the lease liability.

The Right-of-use ("ROU") asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for lease payments made at or before the lease commencement date, plus any initial direct costs incurred less any lease incentives received.

For operating leases, the ROU asset is subsequently measured throughout the lease term at the carrying amount of the lease liability, plus initial direct costs, plus (minus) any prepaid (accrued) lease payments, less the unamortized balance of lease incentives received. Lease expense for lease payments is recognized on a straight-line basis over the lease term.

We monitor for events or changes in circumstances that require a reassessment of a lease. When a reassessment results in the re-measurement of a lease liability, a corresponding adjustment is made to the carrying amount of the corresponding ROU asset unless doing so would reduce the carrying amount of the ROU asset to an amount less than zero. In that case, the amount of the adjustment that would result in a negative ROU asset balance is recorded in profit or loss.

We have lease agreements which include lease and non-lease components. We have elected to combine lease and non-lease components for all lease contracts.

We have elected not to recognize ROU assets and lease liabilities for all short-term leases that have a lease term of 12 months or less. We recognize the lease payments associated with our short-term leases as an expense on a straight-line basis over the lease term.

We adopted ASU 2016-02 using a modified retrospective transition approach as of the effective date as permitted by the amendments in ASU 2018-11, which provides an alternative modified retrospective transition method. As a result, we were not required to adjust our comparative period financial information for effects of the standard or make the new required lease disclosures for periods before the date of adoption (i.e. January 1, 2019). We have elected to adopt the package of transition practical expedients and, therefore, have not reassessed (1) whether existing or expired contracts contain a lease, (2) lease classification for existing or expired leases or (3) the accounting for initial direct costs that were previously capitalized. We did not elect the practical expedient to use hindsight for leases existing at the adoption date.

Exploration and Development Costs

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

The Company evaluates unproved property periodically for impairment. The impairment assessment considers results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. If it is determined that future appraisal drilling or development activities are unlikely to occur, the associated capitalized costs are recorded as exploration expense in the consolidated statement of operations.

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 depleted 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, depreciation and amortization 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. 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. Oil and gas properties are grouped in accordance with ASC 932 — Extractive Activities-Oil and Gas. The basis for grouping is a reasonable aggregation of properties typically by field or by logical grouping of assets with significant shared infrastructure.

For long-lived assets whereby the carrying value exceeds the estimated future undiscounted cash flows, the carrying amount is reduced to fair value. Fair value is generally estimated using the income approach described in the ASC 820 — Fair Value Measurement. If applicable, we utilize prices and other relevant information generated by market transactions involving assets and liabilities that are identical or comparable to the item being measured as the basis for determining fair value. The expected future cash flows used for impairment reviews and related fair value measurements are typically based on judgmental assessments of future production, pricing estimates, capital and operating costs, market-based weighted average cost of capital, and risk adjustment factors applied to reserves. These assumptions are applied to develop future cash flow projections that are then discounted to estimated fair value, using a market-based weighted-average cost of capital. Although we base the fair value estimate of each asset group on assumptions we believe to be reasonable, those assumptions are inherently unpredictable and uncertain, and actual results could differ from the estimate. Negative revisions of estimated reserve quantities, increases in future cost estimates, divestiture of a significant component of the asset group, or sustained decreases in crude oil prices could lead to a reduction in expected future cash flows and possibly an additional impairment of long-lived assets in future periods.

We believe the assumptions used in our analysis to test for impairment are appropriate and result in a reasonable estimate of future cash flows and fair value. Kosmos has consistently used an average of third-party industry forecasts to determine our pricing assumptions. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the evaluation.

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 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.

Revenue Recognition

We recognize revenues on the volumes of hydrocarbons sold to a purchaser. 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, 2020 and 2019, we had no oil and gas imbalances recorded in our consolidated financial statements.

Our oil and gas revenues are recognized when hydrocarbons have been sold to a purchaser at a fixed or determinable price, title has transferred and collection 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,		
	2020	2019	2018
		(In thousands)	
Revenues from contract with customer - Equatorial Guinea	$ 149,033	$ 297,831	$ —
Revenues from contract with customer - Ghana	375,603	740,464	741,033
Revenues from contract with customers - U.S. Gulf of Mexico	285,017	459,960	147,596
Provisional oil sales contracts	(5,620)	1,161	(1,963)
Oil and gas revenue	$ 804,033	$ 1,499,416	$ 886,666

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.

Restructuring Charges

The Company accounts for restructuring charges and related termination benefits in accordance with ASC 712-Compensation-Nonretirement Postemployment Benefits. Under this standard, the costs associated with termination benefits are recorded during the period in which the liability is incurred. During the years ended December 31, 2020 and 2019, we recognized $16.5 million and $11.5 million, respectively, in restructuring charges for employee severance and related benefit costs incurred as part of a corporate reorganization in Other expenses, net in the consolidated statement of operations.

Treasury Stock

We record treasury stock purchases at cost. Our treasury 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. Our treasury stock consists of a share repurchase in 2018 and 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.

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 years ended December 31, 2020, 2019 and 2018 revenue from Phillips 66 Company made up approximately 23%, 20% and 11%, respectively, of our total consolidated revenue and was included in our U.S. Gulf of Mexico segment.

Recent Accounting Standards

Recently Adopted

In June 2016, ASU 2016-13, "Measurement of Credit Losses on Financial Instruments," was issued requiring measurement of all expected credit losses for certain types of financial instruments, including trade receivables, held at the reporting date based on historical experience, current conditions and reasonable and supportable forecasts. This standard was effective January 1, 2020. We assessed all receivable positions for expected credit losses through the implementation of ASU 2016-13, current expected credit loss standard (CECL). Our receivables are collectible in the original term of the underlying agreements and current expected credit losses under the CECL standard are not significant.

Not Yet Adopted

In December 2019, the FASB issued ASU 2019-12, “Simplifying the Accounting for Income Taxes”. The amendments in the ASU are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. Early adoption is permitted, however, we do not plan to early adopt ASU 2019-12. ASU 2019-12 is not expected to have a material impact on our income tax expense.

3. Acquisitions and Divestitures

2020 Transactions

During the third quarter of 2020, Kosmos entered into an agreement with Shell to farm down interests in a portfolio of frontier exploration assets for cash consideration of $96.0 million and future contingent consideration of up to $100.0 million. Under the terms of the agreement, Shell acquired Kosmos' participating interest in blocks offshore Sao Tome and Principe (excluding Block 5 offshore Sao Tome and Principe), Suriname, and Namibia, and will acquire our participating interest in South Africa. Kosmos received proceeds totaling $95.0 million during the fourth quarter of 2020 resulting in gain on sale of assets of $92.1 million, with the remaining proceeds of $1.0 million related to Kosmos' participating interest in South Africa expected to be received in 2021 upon customary approval by the government of The Republic of South Africa. The future contingent consideration is based on the outcome of the first four wells drilled in the purchased assets, excluding South Africa, and is payable upon submission of an appraisal plan to the relevant governmental authority under the relevant host government contract. Shell will pay $50.0 million for each appraisal plan submitted, capped in the aggregate at a maximum of $100.0 million.

In October 2020, Kosmos withdrew from Block C6 offshore Mauritania.

In May 2020, a withdrawal notice for our blocks offshore Cote d'Ivoire was issued to partners and the Government of Cote d'Ivoire.

In July 2020, we provided notice that we declined to enter the final exploration phase of the Suriname Block 45 petroleum agreement.

2019 Transactions

During the first quarter of 2019, we agreed to a petroleum contract covering offshore Marine XXI block with the national oil company of the Republic of the Congo, Société Nationale des Pétroles du Congo. The petroleum contract was subject to a required governmental approval process before the petroleum contract could be made effective. The petroleum contract had not been approved by the government of the Republic of Congo nor entered into force when, in February 2020, we terminated our interests in the Marine XXI block petroleum contract.

In March 2019, we completed an agreement to acquire Ophir's remaining interest in Block EG-24, offshore Equatorial Guinea, which increased our participating interest to 80% and named Kosmos as operator. The Equatorial Guinean national oil company, GEPetrol, has a 20% carried interest during the exploration period. Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest.

In September 2019, we completed a farm-in agreement with OK Energy to acquire a 45% non-operated interest in the Northern Cape Ultra Deep block offshore the Republic of South Africa. The petroleum contract covers approximately 6,930 square kilometers at water depths ranging from 2,500 to 3,100 meters and has an initial exploration phase of two years.

In November 2019, we completed a farm-out agreement with Shell Sao Tome and Principe B.V. to farm-out a 20% participating interest in Block 6 and a 30% participating interest in Block 11, offshore Sao Tome and Principe, resulting in our participating interests in Blocks 6 and 11 being 25% and 35%, respectively. During the year ended December 31, 2019, we recognized a $10.5 million gain related to the farm-out of Blocks 6 and 11 offshore Sao Tome and Principe.

2018 Transactions

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.

In June 2018, we completed a farm-in agreement with a subsidiary of Ophir for Block EG-24, offshore Equatorial Guinea, whereby we acquired our initial non-operated participating interest of 40%. As part of the agreement, we reimbursed a portion of Ophir's previously incurred exploration costs and agreed to carry Ophir's share of the costs. 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. The Equatorial Guinean national oil company, GEPetrol, has a 20% carried interest during the exploration period. Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest.

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.

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 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 focused on Namibia where Kosmos completed a farm-in to Shell's acreage in PEL 39, and Sao Tome and Principe where we 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, our two companies jointly evaluated opportunities in adjacent geographies. This alliance was consistent with Kosmos’ strategy of partnering with supermajors to leverage complementary skill sets. As part of Kosmos' agreement with Shell in the third quarter of 2020 to farm down interests in a portfolio of frontier exploration assets, the alliance was terminated.

4. Joint Interest Billings and Notes Receivables

Joint Interest Billings

The Company’s joint interest billings consist of receivables from partners with interests in common oil and gas properties operated by the Company for shared costs. 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 Ghana, the contractor group funded GNPC’s 5% share of 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, 2020 and 2019, the current portion of the joint interest billing receivables due from GNPC for the TEN fields' development costs were $5.8 million and $14.0 million, respectively, and the long-term portion were $21.2 million and $16.0 million.

Notes Receivables

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 incurred through first gas production for Greater Tortue Ahmeyim Phase 1, currently projected in 2023. Kosmos’ share for the two agreements combined is up to $239.7 million, which is to be repaid with interest through the national oil companies’ share of future revenues. As of December 31, 2020 and 2019, the balance due from the national oil companies was $96.3 million, and $27.4 million, respectively, which is classified as Long-term receivables in our consolidated balance sheets.

5. Property and Equipment

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

	December 31,	
	2020	2019
	(In thousands)	
Oil and gas properties:		
Proved properties	$ 5,369,737	$ 4,904,648
Unproved properties	495,390	814,065
Total oil and gas properties	5,865,127	5,718,713
Accumulated depletion	(2,554,851)	(2,093,962)
Oil and gas properties, net	3,310,276	3,624,751
Other property	59,949	61,598
Accumulated depreciation	(49,312)	(44,017)
Other property, net	10,637	17,581
Property and equipment, net	$ 3,320,913	$ 3,642,332

We recorded depletion expense of $460.9 million, $542.9 million and $316.3 million and depreciation expense of $5.5 million, $6.9 million and $4.6 million for the years ended December 31, 2020, 2019 and 2018, respectively. During the years ended December 31, 2020, 2019 and 2018, we recorded asset impairments totaling $154.0 million, zero and zero, respectively, in our consolidated statement of operations in connection with fair value assessments for oil and gas proved properties in the U.S. Gulf of Mexico.

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 drilled wells as of and during the years ended December 31, 2020, 2019 and 2018.

	Years Ended December 31,		
	2020	2019	2018
	(In thousands)		
Beginning balance	$ 445,790	$ 367,665	$ 410,113
Additions to capitalized exploratory well costs pending the determination of proved reserves	4,001	78,125	10,518
Additions associated with the acquisition of DGE	—	—	26,224
Reclassification due to determination of proved reserves(1)	(263,502)	—	(26,224)
Capitalized exploratory well costs charged to expense(2)	—	—	(52,966)
Ending balance	$ 186,289	$ 445,790	$ 367,665

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(1) Represents the reclassification of exploratory well costs associated with the Greater Tortue Ahmeyim Unit as a result of the execution of the Tortue Phase 1 SPA in February 2020 and Nearly Headless Nick well costs associated with the DGE acquisition in 2018. As of December 31, 2020, due to pricing revisions related to the decrease in commodity prices during the year the Greater Tortue Ahmeyim Unit did not have proved reserves recognition.

(2) Primarily related to Akasa and Wawa wells as we wrote off $38.1 million and $13.6 million, respectively, of previously capitalized 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,		
	2020	2019	2018
	(In thousands, except well counts)		
Exploratory well costs capitalized for a period of one year or less	$ —	$ 29,121	$ —
Exploratory well costs capitalized for a period of one to two years	28,692	78,245	299,253
Exploratory well costs capitalized for a period of three years or longer	157,597	338,424	68,412
Ending balance	$ 186,289	$ 445,790	$ 367,665
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	3	3	3

As of December 31, 2020, the projects with exploratory well costs capitalized for more than one year since the completion of drilling are related to the BirAllah discovery (formerly known as the Marsouin discovery) in Block C8 offshore Mauritania, and the Yakaar and Teranga discoveries in the Cayar Offshore Profond block offshore Senegal.

BirAllah Discovery — In November 2015, we completed the Marsouin-1 exploration well in the northern part of Block C8 offshore Mauritania, which encountered hydrocarbon pay. Following additional evaluation, a decision regarding commerciality is expected be made. During the fourth quarter of 2019, we completed the nearby Orca-1 exploration well which encountered hydrocarbon pay. Following additional evaluation, a decision regarding commerciality is expected to be made. The Bir Allah and Orca discoveries are being analyzed as a potential joint development.

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 to the government of Senegal. In September 2019, we completed the Yakaar-2 appraisal well which encountered hydrocarbon pay. The Yakaar-2 well was drilled approximately nine kilometers from the Yakaar-1 exploration well. Following additional evaluation, a decision regarding commerciality is expected to be made. The Yakaar and Teranga discoveries are being analyzed as a joint development.

Asam Discovery - In October 2019, we completed the S-5 exploration offshore Equatorial Guinea, which encountered hydrocarbon pay. In July 2020, an appraisal plan was approved by the government of Equatorial Guinea. The well is located within tieback range of the Ceiba FPSO and work is currently ongoing to integrate all available data into models to establish the scale of the discovered resource. Additionally, engineering is progressing concepts around required subsea infrastructure necessary for a subsea tieback. Once the appraisal plan involving this work is complete, a decision regarding commerciality will be made.

7. Leases

We have commitments under operating leases primarily related to office leases. Our leases have initial lease terms ranging from one year to ten years. Certain lease agreements contain provisions for future rent increases.

The components of lease cost for the years ended December 31, 2020 and 2019 is as follows:

	December 31, 2020	December 31, 2019
	(In thousands)	
Operating lease cost	$ 5,869	$ 5,480
Short-term lease cost(1)	13,705	15,874
Total lease cost	$ 19,574	$ 21,354

(1) Includes $12.6 million and $13.9 million during the years ended December 31, 2020 and 2019, respectively, of costs associated with short-term drilling contracts.

Other information related to operating leases at December 31, 2020 and 2019, is as follows:

	December 31 2020	December 31 2019
	(In thousands, except lease term and discount rate)	
Balance sheet classifications		
Other assets (right-of-use assets)	$ 19,799	$ 20,008
Accrued liabilities (current maturities of leases)	1,405	1,139
Other long-term liabilities (non-current maturities of leases)	22,771	22,240
Weighted average remaining lease term	8.4 years	8.8 years
Weighted average discount rate	9.8 %	9.8 %

The table below presents supplemental cash flow information related to leases during the years ended December 31, 2020 and 2019:

	December 31, 2020	December 31, 2019
	(In thousands)	
Operating cash flows for operating leases	$ 5,225	$ 5,082
Investing cash flows for operating leases(1)	12,586	13,855

(1) Represents costs associated with short-term drilling contracts.

Future minimum rental commitments under our leases at December 31, 2020, are as follows:

	Operating Leases(1) (In thousands)
2021	$ 3,307
2022	4,216
2023	4,287
2024	4,358
2025	4,429
Thereafter	15,470
Total undiscounted lease payments	$ 36,067
Less: Imputed interest	(11,891)
Total lease liabilities	$ 24,176

(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.

8. Debt

	December 31,	
	2020	2019
	(In thousands)	
Outstanding debt principal balances:		
Facility	$ 1,200,000	$ 1,400,000
Corporate Revolver	100,000	—
Senior Notes	650,000	650,000
GoM Term Loan	200,000	—
Total	2,150,000	2,050,000
Unamortized deferred financing costs and discounts(1)	(38,569)	(41,937)
Total debt, net	2,111,431	2,008,063
Less: Current maturities of long-term debt	(7,500)	—
Long-term debt, net	$ 2,103,931	$ 2,008,063

(1) Includes $25.6 million and $32.8 million of unamortized deferred financing costs related to the Facility; $8.4 million and $9.1 million of unamortized deferred financing costs and discounts related to the Senior Notes; and $4.6 million and zero of unamortized deferred financing costs related to the GoM Term Loan as of December 31, 2020 and December 31, 2019, respectively.

Facility

The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities with a borrowing base calculation that includes value related to the Jubilee, TEN, Ceiba and Okume fields. 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 taking total commitments to $1.6 billion. 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. The commitments were reduced by $100.0 million to $1.6 billion following the Senior Notes issuance in April 2019. In April 2020, following the lenders' annual redetermination, the available borrowing base and Facility size were both reduced from $1.6 billion to approximately $1.5 billion. In addition, as part of the April 2020 redetermination process, the Company agreed to conduct an additional redetermination in September 2020. As a result, in October 2020, the available borrowing base was reduced to approximately $1.32 billion. The Company made repayments totaling $250 million during the fourth quarter of 2020. Additionally, the Company agreed to conduct semi-annual redeterminations every March and September, beginning with March 2021. When our net leverage ratio exceeds 2.50x, we are required under the Facility to maintain a restricted cash balance that is sufficient to meet the payment of interest and fees for the next six-month period on the 7.125% Senior Notes plus the Corporate Revolver or the Facility, whichever is greater. As of December 31, 2020, we exceeded this ratio and restricted approximately $28.5 million in cash to meet our requirements in January 2021.

As of December 31, 2020, borrowings under the Facility totaled $1.2 billion and the undrawn availability under the Facility was $120.0 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 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, 2020, 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. In October 2020, the Company agreed to conduct semi-annual redeterminations every March and September, beginning with March 2021. 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 below contained in the Facility as of September 30, 2020 (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 interest cover ratio (as defined in the glossary), not less than 2.25x.
- the debt cover ratio (as defined in the glossary), amended as described below:

As result of the impact of COVID-19 on the demand for oil and the related significant decrease in oil prices, our ability to comply with one of our financial covenants, the debt cover ratio, may be impacted in future periods. Therefore, in July 2020, we proactively worked with our lender group, prior to any inability to comply with the financial covenants thereunder, to amend the debt cover ratio calculation through December 31, 2021. The amendment makes this covenant less restrictive during the stated period up to a maximum of 4.75x and thereafter gradually returns to the originally agreed upon ratio of 3.5x. We were in compliance with the financial covenants as of the most recent assessment date. The Facility contains customary cross default provisions.

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 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. As of December 31, 2020, we have $3.7 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, 2020, there were $100.0 million in outstanding borrowings under the Corporate Revolver and the undrawn availability under the Corporate Revolver was $300.0 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 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.

We were in compliance with the financial covenants below contained in the Corporate Revolver as of September 30, 2020 (the most recent assessment date), which requires the maintenance of:

- the interest cover ratio (as defined in the glossary), not less than 2.25x.
- the debt cover ratio (as defined in the glossary), amended as described below:

As result of the impact of COVID-19 on the demand for oil and the related significant decrease in oil prices, our ability to comply with one of our financial covenants, the debt cover ratio, may be impacted in future periods. Therefore, in July 2020, we proactively worked with our lender group, prior to any inability to comply with the financial covenants thereunder, to amend the debt cover ratio calculation through December 31, 2021. The amendment makes this covenant less restrictive during the stated period up to a maximum of 4.75x and thereafter gradually returns to the originally agreed upon ratio of 3.5x. We were in compliance with the financial covenants as of the most recent assessment date. The Corporate Revolver contains customary cross default provisions.

Letters of Credit

In July 2016, we amended and restated the revolving letter of credit facility agreement ("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. 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. The LC Facility expired in July 2019, however, there were five outstanding letters of credit totaling $3.1 million which were released in May 2020, and the LC Facility was subsequently terminated in June 2020.

In 2019, we issued two letters of credit totaling $20.4 million under a new letter of credit arrangement, which did not require cash collateral. In December 2020, as a result of the Shell farm down transaction discussed in Note 3 — Acquisitions and Divestitures, the letters of credit were released.

7.875% Senior Secured Notes due 2021

In April 2019, all of the Senior Secured Notes were redeemed for $543.8 million, including accrued interest and the early redemption premium. The redemption resulted in a $22.9 million loss on extinguishment of debt, which is included in Interest and other financing costs, net on the consolidated statement of operations.

7.125% Senior Notes due 2026

In April 2019, the Company issued $650.0 million of 7.125% Senior Notes and received net proceeds of approximately $640.0 million after deducting commissions and other expenses. We used the net proceeds to redeem all of the

Senior Secured Notes, repay a portion of the outstanding indebtedness under the Corporate Revolver and pay fees and expenses related to the redemption, repayment and the issuance of the Senior Notes.

The Senior Notes mature on April 4, 2026. We will pay interest in arrears on the Senior Notes each April 4 and October 4, commencing on October 4, 2019. The Senior Notes are senior, unsecured obligations of Kosmos Energy Ltd. and rank equal in right of payment with all of its existing and future senior indebtedness (including all borrowings under the Corporate Revolver) and rank effectively junior in right of payment to all of its existing and future secured indebtedness (including all borrowings under the Facility). The Senior Notes are guaranteed on a senior, unsecured basis by certain subsidiaries owning the Company's U.S. Gulf of Mexico assets, and on a subordinated, unsecured basis by certain subsidiaries that guarantee the Facility.

At any time prior to April 4, 2022, and subject to certain conditions, the Company may, on one or more occasions, redeem up to 40% of the original principal amount of the Senior Notes with an amount not to exceed the net cash proceeds of certain equity offerings at a redemption price of 107.1% of the outstanding principal amount of the Senior Notes, together with accrued and unpaid interest and premium, if any, to, but excluding, the date of redemption. Additionally, at any time prior to April 4, 2022 the Company may, on any one or more occasions, redeem all or a part of the Senior Notes at a redemption price equal to 100%, plus any accrued and unpaid interest, and plus a “make-whole” premium. On or after April 4, 2022, 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 April 4, 2022, but before April 4, 2023	103.6 %
On or after April 4, 2023, but before April 4, 2024	101.8 %
On or after April 4, 2024 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 Senior Notes 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 Senior Notes 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.

The Senior Notes 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.

Production Prepayment Agreement, net

In June 2020, the Company received $50 million from Trafigura under a Production Prepayment Agreement of crude oil sales related to a portion of our U.S. Gulf of Mexico production primarily in 2022 and 2023. The Company has terminated the Production Prepayment Agreement and the initial prepayment of $50 million advanced under the Production Prepayment Agreement by Trafigura in the second quarter of 2020 has been extinguished and converted into the GoM Term Loan as of September 30, 2020.

GoM Term Loan

In September 2020, the Company entered into a five-year $200 million senior secured term-loan credit agreement secured against the Company's U.S. Gulf of Mexico assets with net proceeds received of $197.7 million after deducting fees and other expenses. The GoM Term Loan also includes an accordion feature providing for incremental commitments of up to $100 million subject to certain conditions. The net proceeds will be used to pay down a portion of the Facility and to fund U.S.

Gulf of Mexico working capital and general operating expenses. The $50 million advanced under the Production Prepayment Agreement with Trafigura in the second quarter of 2020 has been extinguished and converted as part of the GoM Term Loan with the remaining $150 million provided by an affiliate of Beal Bank. The GoM Term Loan bears interest at an effective rate of approximately 6% per annum and matures in 2025, with principal repayments beginning in the fourth quarter of 2021.

The GoM Term Loan contains customary affirmative and negative covenants, including covenants that affect our ability to incur additional indebtedness, create liens, merge, dispose of assets, and make distributions, dividends, investments or capital expenditures, among other things. The GoM Term Loan is guaranteed on a senior, secured basis by certain subsidiaries owning the Company's U.S. Gulf of Mexico assets.

The GoM Term Loan includes certain representations and warranties, indemnities and events of default that, subject to certain materiality thresholds and grace periods, arise as a result of a payment default, failure to comply with covenants, material inaccuracy of representation or warranty, and certain bankruptcy or insolvency proceedings. If there is an event of default, all or any portion of the outstanding indebtedness may be immediately due and payable and other rights may be exercised including against the collateral.

At December 31, 2020, the estimated repayments of debt during the five years and thereafter are as follows:

	Payments Due by Year						
	Total	2021	2022	2023	2024	2025	Thereafter
	(In thousands)						
Principal debt repayments(1)	$ 2,150,000	$ 7,500	$ 258,571	$ 458,571	$ 458,572	$ 316,786	$ 650,000

(1) Includes the scheduled maturities for the $650.0 million aggregate principal amount of Senior Notes and borrowings under the Facility, Corporate Revolver and GoM Term Loan. The scheduled maturities of debt related to the Facility as of December 31, 2020 are based on 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,		
	2020	2019	2018
	(In thousands)		
Interest expense	$ 119,857	$ 145,507	$ 114,134
Amortization—deferred financing costs	9,347	9,257	9,379
Loss on extinguishment of debt	2,902	24,794	4,324
Capitalized interest	(25,013)	(28,077)	(28,331)
Deferred interest	2,402	1,919	(1,138)
Interest income	(4,773)	(3,692)	(3,455)
Other, net	5,072	5,366	6,263
Interest and other financing costs, net	$ 109,794	$ 155,074	$ 101,176

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.

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, 2020. 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**
2021:								
January — December	Swaps with sold puts	Dated Brent	6,000	$ —	$ 53.96	$ 42.92	$ —	$ —
January — June	Swaps with sold puts	NYMEX WTI	1,000	—	47.75	37.50	—	—
January — December	Three-way collars	Dated Brent	4,000	0.34	—	33.13	40.63	52.60
January — December	Three-way collars	NYMEX WTI	1,000	1.00	—	37.50	45.00	55.00
January — December	Sold calls(1)	Dated Brent	7,000	—	—	—	—	70.09
2022:								
January — December	Sold calls(1)	Dated Brent	1,581	—	—	—	—	60.00

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

In February 2021, we entered into Dated Brent three-way collar contracts for 1.5 MMBbl from January 2022 through December 2022 with a sold put price of $40.00 per barrel, a floor price of $50.00 per barrel and a ceiling price of $70.00 per barrel.

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, 2020 and 2019 and gain/(loss) from derivatives during the years ended December 31, 2020, 2019 and 2018.

		Estimated Fair Value Asset (Liability)	
		December 31,	
Type of Contract	**Balance Sheet Location**	**2020**	**2019**
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative assets:			
Commodity	Derivatives assets—current	$ 15,414	$ 12,856
Provisional oil sales	Receivables: Oil sales	(677)	(3,287)
Commodity	Derivatives assets—long-term	964	2,302
Derivative liabilities:			
Commodity	Derivatives liabilities—current	(28,009)	(8,914)
Commodity	Derivatives liabilities—long-term	(8,069)	(11,478)
Total derivatives not designated as hedging instruments		$ (20,377)	$ (8,521)

Type of Contract	Location of Gain/(Loss)	Amount of Gain/(Loss) Years Ended December 31, 2020	2019	2018
		(In thousands)		
Derivatives not designated as hedging instruments:				
Commodity(1)	Oil and gas revenue	$ (5,620)	$ 1,161	$ (1,963)
Commodity	Derivatives, net	(17,180)	(71,885)	31,430
Interest rate	Interest expense	—	—	493
Total derivatives not designated as hedging instruments		$ (22,800)	$ (70,724)	$ 29,960

(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, 2020 and 2019, 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, 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, 2020 and 2019, for each fair value hierarchy level:

	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, 2020				
Assets:				
Commodity derivatives	$ —	$ 16,378	$ —	$ 16,378
Provisional oil sales	—	(677)	—	(677)
Liabilities:				
Commodity derivatives	—	(36,078)	—	(36,078)
Total	$ —	$ (20,377)	$ —	$ (20,377)
December 31, 2019				
Assets:				
Commodity derivatives	$ —	$ 15,158	$ —	$ 15,158
Provisional oil sales	—	(3,287)	—	(3,287)
Liabilities:				
Commodity derivatives	—	(20,392)	—	(20,392)
Total	$ —	$ (8,521)	$ —	$ (8,521)

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

Commodity Derivatives

Our commodity derivatives represent crude oil collars, put options, call options and swaps for notional barrels of oil at fixed Dated Brent, 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.

Debt

The following table presents the carrying values and fair values at December 31, 2020 and 2019:

	December 31, 2020		December 31, 2019	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Senior Notes	$ 643,524	$ 613,412	$ 642,550	$ 664,957
GoM Term Loan	200,000	200,000	—	—
Corporate Revolver	100,000	100,000	—	—
Facility	1,200,000	1,200,000	1,400,000	1,400,000
Total	$ 2,143,524	$ 2,113,412	$ 2,042,550	$ 2,064,957

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 values of the GoM Term Loan, Corporate Revolver and Facility approximate fair value since they are subject to short-term floating interest rates that approximate the rates available to us for those periods.

Nonrecurring Fair Value Measurements - Long-lived assets

Certain long-lived assets are reported at fair value on a non-recurring basis on the Company's consolidated balance sheet. These long-lived assets are not measured at fair value on an ongoing basis but are subject to fair value adjustments in certain circumstances. Our long-lived assets are reviewed for impairment when changes in circumstances indicate that the carrying amount of an asset may not be recoverable.

The Company calculates the estimated fair values of its long-lived assets using the income approach described in the ASC 820 — Fair Value Measurements. Significant inputs associated with the calculation of estimated discounted future net cash flows include anticipated future production, pricing estimates, capital and operating costs, market-based weighted average cost of capital, and risk adjustment factors applied to reserves. These are classified as Level 3 fair value assumptions. The Company utilizes an average of third-party industry forecasts of Dated Brent, adjusted for location and quality differentials, to determine our pricing assumptions. In order to evaluate the sensitivity of the assumptions, we analyze sensitivities to prices, production, and risk adjustment factors.

As a result of the impact of COVID-19 on the demand for oil and the related significant decrease in oil prices, we reviewed our long-lived assets for impairment at March 31, 2020, which resulted in impairment charges of $150.8 million, reducing the carrying value of the properties to their estimated fair values of $243.7 million. As part of our impairment analysis, the average per barrel Dated Brent price of third-party industry forecasts used for purposes of determining discounted future cash flows ranged from the mid-$30s in 2020 increasing to the mid-$50s over several years. The expected future cash flows were discounted using a rate of approximately 10 percent, which the Company believes is a market-based weighted average cost of capital for industry peers determined appropriate at the time of the valuation. These impairment charges are included in Impairments of long-lived assets on the consolidated statement of operations.

The Company did not recognize additional impairment of proved oil and gas properties during the second and third quarters of 2020 as no impairment indicators were identified. During the fourth quarter of 2020 the Company recorded additional impairment charges totaling approximately $3.2 million resulting in impairment charges totaling $154.0 million for the year ended December 31, 2020. If we experience further declines in oil pricing expectations, increases in our estimated future expenditures or a decrease in our estimated production profile, our long-lived assets could be at risk of additional impairment.

11. Asset Retirement Obligations

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

	December 31,	
	2020	2019
	(In thousands)	
Asset retirement obligations:		
Beginning asset retirement obligations	$ 235,053	$ 151,953
Additions associated with Equatorial Guinea - Ceiba Field and Okume Complex	—	114,395
Liabilities incurred during period	3,436	11,218
Liabilities settled during period	(2,782)	(7,156)
Revisions in estimated retirement obligations	(3,736)	(49,471)
Accretion expense	19,450	14,114
Ending asset retirement obligations	$ 251,421	$ 235,053

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. The revisions in estimated retirement obligations during 2020 and 2019 are related to changes in the estimated abandonment date in certain of our fields.

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 going forward is accounted for under the proportionate consolidation method of accounting, which includes additions to our asset retirement obligations.

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, 2020, the Company had approximately 6.5 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 $32.7 million, $32.4 million and $35.2 million during the years ended December 31, 2020, 2019 and 2018, respectively. The total tax benefit for the years ended December 31, 2020, 2019 and 2018 was $4.7 million, $4.9 million and $6.6 million, respectively. Additionally, we expensed a net tax shortfall (windfall) related to equity-based compensation of $1.3 million, $1.2 million and $(0.4) million for the years ended December 31, 2020, 2019 and 2018, respectively. The fair value of awards vested during 2020, 2019 and 2018 was approximately $26.0 million, $20.3 million, and $85.1 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, 2020:

	Service Vesting Restricted Stock Awards	Weighted- Average Grant-Date Fair Value	Market / Service Vesting Restricted Stock Awards	Weighted- Average Grant-Date Fair Value
	(In thousands)		(In thousands)	
Outstanding at December 31, 2017:	220	$ 8.64	—	$ —
Granted	—	—	—	—
Forfeited	—	—	—	—
Vested	(220)	8.64	—	—
Outstanding at December 31, 2018:	—	—	—	—

There has been no additional restricted stock activity subsequent to December 31, 2018.

The following table reflects the outstanding restricted stock units as of December 31, 2020:

	Service Vesting Restricted Stock Units	Weighted- Average Grant-Date Fair Value	Market / Service Vesting Restricted Stock Units	Weighted-Average Grant-Date Fair Value
	(In thousands)		(In thousands)	
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
Granted	3,228	5.01	3,195	6.02
Forfeited	(591)	5.90	(813)	7.93
Vested	(2,021)	5.95	(1,300)	6.32
Outstanding at December 31, 2019:	4,731	5.71	7,798	8.42
Granted	3,481	5.48	3,394	8.37
Forfeited	(1,187)	6.12	(726)	8.03
Vested	(2,185)	5.91	(2,607)	9.47
Outstanding at December 31, 2020:	4,840	5.34	7,859	8.11

As of December 31, 2020, total equity-based compensation to be recognized on unvested restricted stock units is $22.9 million over a weighted average period of 1.7 years.

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 $1.06 to $12.96 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 52.0%. 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 0.8% to 2.5% for restricted stock units. The expected quarterly dividends ranged from $0.045 to $0.050 commensurate with our current dividend experience.

In January 2021, we granted 2.5 million service vesting restricted stock units and 6.7 million market and service vesting restricted stock units to our employees under our long-term incentive plan. We expect to recognize approximately $32.2 million of non-cash compensation expense related to these grants over the next three years.

13. Income Taxes

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.

In March 2020, the Coronavirus Aid, Relief, and Economic Security ACT ("CARES Act") became law. Among other things, the CARES Act permits taxpayers to carry back U.S. taxable losses generated during tax years 2018 through 2020 to the five tax years preceding the loss year to obtain tax refunds. Certain of our U.S. legal entities qualify for such relief and we recorded a current tax benefit of $4.9 million during the first quarter of 2020, with a total $12.2 million income tax refund claim. Other provisions of the CARES Act are not expected to have a material impact to our tax expense.

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 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. The following discussion reflects the proportionate consolidation of our Equatorial Guinean operations related to the Ceiba Field and Okume Complex for the years ended December 31, 2020 and 2019. For years ended prior to 2019 KTIPI was accounted for as an Equity Method Investment.

The components of loss before income taxes were as follows:

	Years Ended December 31,		
	2020	2019	2018
	(In thousands)		
United States	$ (338,746)	$ (149,919)	$ 41,026
Bermuda	—	—	(73,979)
Foreign—other	(78,049)	175,036	(17,907)
Income (loss) before income taxes	$ (416,795)	$ 25,117	$ (50,860)

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

	Years Ended December 31,		
	2020	2019	2018
	(In thousands)		
Current:			
United States	$ (12,208)	$ 185	$ 122
Bermuda	—	—	—
Foreign—other	49,586	171,079	33,864
Total current	37,378	171,264	33,986
Deferred:			
United States	34,831	(18,776)	8,514
Bermuda	—	—	—
Foreign—other	(77,418)	(71,594)	631
Total deferred	(42,587)	(90,370)	9,145
Income tax expense (benefit)	$ (5,209)	$ 80,894	$ 43,131

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

	Years Ended December 31,		
	2020	2019	2018
	(In thousands)		
Tax at statutory rate(1)	$ (87,527)	$ 5,275	$ (10,681)
Foreign income (loss) taxed at different rates	(1,771)	32,690	5,013
Net non-taxable expense / insurance recoveries	—	(13,352)	3,256
West Leo arbitration settlement	—	—	(2,834)
Non-deductible insurance premiums	—	2,625	—
Non-deductible compensation	890	3,545	2,643
Deferred tax liability - undistributed earnings	—	—	(2,565)
Non-deductible and other items	387	3,998	656
Equity earnings - net of tax	—	—	(15,305)
Tax shortfall (windfall) on equity-based compensation, net	1,175	1,224	(387)
Change in valuation allowance	86,539	44,889	63,335
U.S. tax loss carryback rate differential	(4,902)	—	—
Total tax expense	$ (5,209)	$ 80,894	$ 43,131
Effective tax rate(2)	1 %	322 %	85 %

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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 2020, 2019 and 2018 reconciliation of income tax expense is the U.S. statutory tax rate of 21%.

(2) The effective tax rate during the years ended December 31, 2020, 2019 and 2018, were impacted by (gains) and losses of $(2.9) million, $132.1 million and $261.2 million, respectively, incurred in jurisdictions in which we are not subject to taxes and therefore do not generate any income tax benefits or where there are valuation allowances offsetting the corresponding deferred tax assets.

The effective tax rate for the United States is approximately 7%, 12% and 84% for the years ended December 31, 2020, 2019 and 2018, respectively. The effective tax rate in the United States is impacted by the effect 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. For the years ended December 31, 2020 and December 31, 2019, our effective tax rate in the United States is impacted by valuation allowances on a portion of our deferred tax assets totaling $96.6 million and $6.8 million, respectively.

The effective tax rate for Ghana is approximately 35%, 29% and 36% for the years ended December 31, 2020, 2019 and 2018, respectively. The effective tax rate in Ghana is impacted by non-deductible expenditures. The effective tax rate for years ended December 31, 2018 and 2019, is impacted by amounts associated with damage to the turret bearing, which we expect to recover from insurance proceeds. Any such insurance recoveries would not be subject to income tax.

The effective tax rate for Equatorial Guinea is approximately 34% and 37% for the years ended December 31, 2020 and 2019 and is impacted by non-deductible expenditures.

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, 2020	December 31, 2019
	(In thousands)	
Deferred tax assets:		
Foreign capitalized operating expenses	$ 152,106	$ 175,330
Foreign net operating losses	32,762	19,576
United States net operating losses	113,427	58,903
United States deferred interest expense	—	15,426
Equity compensation	14,089	13,700
Unrealized derivative losses	3,482	1,471
Asset retirement obligation and other	41,759	43,159
Total deferred tax assets	357,625	327,565
Valuation allowance	(288,288)	(201,749)
Total deferred tax assets, net	69,337	125,816
Deferred tax liabilities:		
Depletion, depreciation and amortization related to property and equipment	(642,956)	(746,258)
Unrealized derivative gains	—	—
Total deferred tax liabilities	(642,956)	(746,258)
Net deferred tax liability	$ (573,619)	$ (620,442)

The Company has foreign net operating loss carryforwards of $105.9 million. Of these losses, we expect $0.5 million, $15.5 million, $0.6 million, $2.1 million, $1.2 million and $43.5 million to expire in 2021, 2022, 2023, 2024, 2025, and 2026 respectively, and $42.5 million do not expire. All of these losses currently have offsetting valuation allowances. The Company has $540.1 million of United States net operating loss that will not expire.

The Company is open to tax examinations in the United States for federal income tax return years 2017 through 2019 and in Ghana to federal income tax return years 2014 through 2019.

As of December 31, 2020, the Company had no material uncertain tax positions. The Company's policy is to recognize potential interest and penalties related to income tax matters in income tax expense.

14. Net Income (Loss) Per Share

In the calculation of basic net income per share, participating securities are allocated earnings based on actual dividend distributions received plus a proportionate share of undistributed net income, if any. We calculate basic net income per share under the two-class method. Diluted net income (loss) per share is calculated under both the two-class method and the treasury stock method and the more dilutive of the two calculations is presented. The computation of diluted net income (loss) per share reflects the potential dilution that could occur if all outstanding awards under our LTIP were converted into 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, 2020	2019	2018
	(In thousands, except per share data)		
Numerator:			
Net loss allocable to common stockholders	$ (411,586)	$ (55,777)	$ (93,991)
Denominator:			
Weighted average number of shares outstanding:			
Basic	405,212	401,368	404,585
Restricted stock awards and units(1)(2)	—	—	—
Diluted	405,212	401,368	404,585
Net loss per share:			
Basic	$ (1.02)	$ (0.14)	$ (0.23)
Diluted	$ (1.02)	$ (0.14)	$ (0.23)

(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, 2020, 2019 and 2018, we excluded 6.1 million, 15.3 million and 10.6 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. All restricted stock awards were fully vested in January 2018.

15. Commitments and Contingencies

From time to time, we are involved in litigation, regulatory examinations and administrative proceedings primarily arising in the ordinary course of our business in jurisdictions in which we do business. Although the outcome of these matters cannot be predicted with certainty, management believes none of these matters, either individually or in the aggregate, would have a material effect upon the Company's financial position; however, an unfavorable outcome could have a material adverse effect on our results from operations for a specific interim period or year.

The Jubilee Field in Ghana covers an area within both the WCTP and DT petroleum contract areas. It was agreed the Jubilee Field would be unitized for optimal resource recovery. Kosmos and its partners executed a comprehensive unitization and unit operating agreement, the Jubilee UUOA, to unitize the Jubilee Field and govern each party's respective rights and duties in the Jubilee Unit, which was effective July 16, 2009. Pursuant to the terms of the Jubilee UUOA, the tract participations are subject to a process of redetermination. The initial redetermination process was completed on October 14, 2011. As a result of the initial redetermination process, our Unit Interest is 24.1%. These consolidated financial statements are based on these redetermined tract participations. Our unit interest may change in the future should another redetermination occur.

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 the 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 Block areas. These interest percentages are subject to redetermination of the participating interests in the Greater Tortue Ahmeyim Field pursuant to the terms of the GTA UUOA. These consolidated financial statements are based our current payment interest on development activities in the Greater Tortue Ahmeyim Unit of 26.7%. Our unit interest may change in the future should a redetermination occur.

We currently have a commitment to drill two exploration wells and approximately 1,000 square kilometer 3D seismic acquisition requirement in Mauritania. In South Africa, as of December 31, 2020, we had 2D seismic acquisition requirements of approximately 500 line kilometers, which was acquired in January 2021.

Performance Obligations

As of December 31, 2020 and 2019, the Company had performance bonds totaling $195.5 million and $222 million, respectively, for our supplemental bonding requirements stipulated by the BOEM and $7.1 million and $3.7 million, respectively, to other operators related to costs anticipated for the plugging and abandonment of certain wells and the removal of certain facilities in our U.S. Gulf of Mexico fields. As of December 31, 2020 and 2019, we had zero cash collateral against these secured performance bonds.

Dividends

On March 26, 2020, the quarterly cash dividend of $0.0452 per common share was paid to stockholders of record as of March 5, 2020. In March 2020, in response to economic conditions, including oil price volatility and the impact of COVID-19 pandemic, the Board of Directors decided to suspend the dividend. During the year ended December 31, 2019 we declared and issued cash dividends to stockholders totaling $0.1808 per common share.

16. Additional Financial Information

Accrued Liabilities

Accrued liabilities consisted of the following:

	December 31,	
	2020	2019
	(In thousands)	
Accrued liabilities:		
Exploration, development and production	$ 89,162	$ 152,490
Revenue payable	15,079	32,482
Current asset retirement obligations	7,255	4,527
General and administrative expenses	4,988	44,575
Interest	23,725	33,584
Income taxes	37,344	103,566
Taxes other than income	2,815	3,375
Derivatives	17,475	4,837
Other	5,417	1,268
	$ 203,260	$ 380,704

Gain on sale of assets

During the year ended December 31, 2020, we recognized a $92.1 million gain related to the farm down of interests in blocks offshore Sao Tome & Principe, Suriname and Namibia to Shell.

During the year ended December 31, 2019, we recognized a $10.5 million gain related to the farm-out of Blocks 6 and 11 offshore Sao Tome and Principe. 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.

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,		
	2020	2019	2018
	(In thousands)		
Loss on disposal of inventory	$ 8,607	$ 4,590	$ 280
Gain on insurance settlements	—	(3,509)	—
Loss on asset retirement obligations liability settlements	1,966	193	—
Restructuring charges	16,474	11,528	—
Other, net	10,755	11,846	(6,781)
Other expenses, net	$ 37,802	$ 24,648	$ (6,501)

The restructuring charges are for employee severance and related benefit costs incurred as part of a corporate reorganization.

Included in Other, net 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 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 2018 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.

Equity Method Investments - Equatorial Guinea

As part of our acquisition of KTIPI in 2017, a corporate joint venture entity in which we owned a 50% interest until January 2019, 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 presented on a 100% basis for 2018. The financial information for 2019 is presented as part of our consolidated financial statements based on our direct 40.375% ownership in the Ceiba Field and Okume Complex.

	December 31, 2018
	(In thousands)
Assets	
Total current assets	$ 149,950
Property and equipment, net	271,627
Other assets	21
Total assets	$ 421,598
Liabilities and shareholders' deficit	
Total current liabilities	$ 226,311
Total long term liabilities	536,178
Shareholders' deficit:	
Total shareholders' deficit	(340,891)
Total liabilities and shareholders' deficit	$ 421,598

	Year Ended December 31, 2018
	(In thousands)
Revenues and other income:	
Oil and gas revenue	$ 721,299
Other income	(477)
Total revenues and other income	720,822
Costs and expenses:	
Oil and gas production	147,685
Depletion and depreciation	126,983
Other expenses, net	429
Total costs and expenses	275,097
Income before income taxes	445,725
Income tax expense	156,981
Net income	$ 288,744
Kosmos' share of net income	$ 144,372
Basis difference amortization(1)	71,491
Equity in earnings - KTIPI	$ 72,881

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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.

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 is accounted for under the proportionate consolidation method of accounting going forward. This transaction was accounted for as an asset acquisition. The carrying value of the equity method investment was allocated to the undivided interest acquired and net working capital based on the estimated relative fair value of the acquired assets.

The estimated fair value measurements of oil and gas assets acquired and 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.

		Carrying Value Allocation (in thousands)
Assets acquired:		
Proved oil and gas properties	$	372,144
Unproved oil and gas properties		103,909
Prepaids and other		7,273
Total assets acquired	$	483,326
Liabilities assumed:		
Asset retirement obligations	$	114,395
Deferred tax liabilities		247,636
Accrued liabilities and other		69,399
Total liabilities assumed	$	431,430
Carrying value:		
Equity method investment carrying value at December 31, 2018	$	51,896

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, 2020, the Company had operations in four geographic reporting segments: Ghana, Equatorial Guinea, Mauritania/Senegal and the U.S. Gulf of Mexico. 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	Mauritania / Senegal	U.S. Gulf of Mexico	Corporate & Other	Eliminations	Total
				(in thousands)			
Year ended December 31, 2020							
Revenues and other income:							
Oil and gas revenue	366,515	$ 152,501	$ —	$ 285,017	$ —	$ —	$ 804,033
Gain on sale of assets	—	—	—	84	92,079	—	92,163
Other income, net	2	—	—	280	120,135	(120,415)	2
Total revenues and other income	366,517	152,501	—	285,381	212,214	(120,415)	896,198
Costs and expenses:							
Oil and gas production	169,357	80,813	—	88,307	—	—	338,477
Facilities insurance modifications, net	13,161	—	—	—	—	—	13,161
Exploration expenses	182	8,290	8,189	26,792	41,163	—	84,616
General and administrative	13,506	4,865	7,464	12,607	129,801	(96,101)	72,142
Depletion, depreciation and amortization	235,772	64,786	61	181,898	3,345	—	485,862
Impairment of long-lived assets	—	—	—	153,959	—	—	153,959
Interest and other financing costs, net(1)	54,530	(1,248)	(27,339)	17,373	73,612	(7,134)	109,794
Derivatives, net	—	—	—	—	17,180	—	17,180
Other expenses, net	(27,925)	2,281	4,829	54,485	21,312	(17,180)	37,802
Total costs and expenses	458,583	159,787	(6,796)	535,421	286,413	(120,415)	1,312,993
Income (loss) before income taxes	(92,066)	(7,286)	6,796	(250,040)	(74,199)	—	(416,795)
Income tax expense (benefit)	(30,486)	2,428	—	26,061	(3,212)	—	(5,209)
Net income (loss)	$ (61,580)	$ (9,714)	$ 6,796	$ (276,101)	$ (70,987)	$ —	$ (411,586)
Consolidated capital expenditures	$ 44,146	$ 38,126	$ 126,803	$ 123,197	$ (58,293)	$ —	$ 273,979
As of December 31, 2020							
Property and equipment, net	$ 1,293,372	$ 426,365	$ 580,920	$ 998,204	$ 22,052	$ —	$ 3,320,913
Total assets	$ 1,397,802	$ 689,222	$ 823,411	$ 3,171,851	$ 12,654,827	$ (14,869,520)	$ 3,867,593

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(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.

	Ghana	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Corporate & Other	Eliminations	Total
				(in thousands)			
Year ended December 31, 2019							
Revenues and other income:							
Oil and gas revenue	$ 738,909	$ 300,547	$ —	$ 459,960	$ —	$ —	$ 1,499,416
Gain on sale of assets	—	—	—	—	10,528	—	10,528
Other income, net	5	—	—	1,194	155,866	(157,100)	(35)
Total revenues and other income	738,914	300,547	—	461,154	166,394	(157,100)	1,509,909
Costs and expenses:							
Oil and gas production	188,207	90,607	—	123,799	—	—	402,613
Facilities insurance modifications, net	(24,254)	—	—	—	—	—	(24,254)
Exploration expenses	204	13,350	11,181	115,765	40,455	—	180,955
General and administrative	18,618	6,643	8,222	25,456	159,539	(108,468)	110,010
Depletion, depreciation and amortization	268,866	75,565	62	214,592	4,776	—	563,861
Interest and other financing costs, net(1)	72,226	(634)	(26,537)	21,266	95,887	(7,134)	155,074
Derivatives, net	—	—	—	30,387	41,498	—	71,885
Other expenses, net	40,382	(563)	12,056	2,691	11,580	(41,498)	24,648
Total costs and expenses	564,249	184,968	4,984	533,956	353,735	(157,100)	1,484,792
Income (loss) before income taxes	174,665	115,579	(4,984)	(72,802)	(187,341)	—	25,117
Income tax expense (benefit)	50,293	49,192	—	(8,419)	(10,172)	—	80,894
Net income (loss)	$ 124,372	$ 66,387	$ (4,984)	$ (64,383)	$ (177,169)	$ —	$ (55,777)
Consolidated capital expenditures	$ 98,285	$ 63,798	$ 12,556	$ 232,891	$ 33,206	$ —	$ 440,736
As of December 31, 2019							
Property and equipment, net	$ 1,487,114	$ 464,420	$ 438,800	$ 1,216,453	$ 35,545	$ —	$ 3,642,332
Total assets	$ 1,654,266	$ 650,607	$ 581,317	$ 3,251,420	$ 12,144,312	$ (13,964,690)	$ 4,317,232

(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.

	Ghana	Equatorial Guinea(1)	Mauritania / Senegal	U.S. Gulf of Mexico(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, depreciation and amortization	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 on equity method investments, net	—	—	—	—	—	(72,881)	(72,881)
Other expenses, net	16,414	(814)	(23)	598	3,510	(26,186)	(6,501)
Total costs and expenses	642,634	251,515	(12,866)	118,271	378,187	(424,512)	953,229
Income (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 income (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

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(1) Includes our proportionate share of our equity method investment in KTIPI, including our basis difference which is reflected in depletion, depreciation and amortization for the year ended December 31, 2018, except for capital expenditures. See Note 16 - Additional Financial Information for additional information regarding our equity method investments.

(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.

	Years Ended December 31,		
	2020	2019	2018
		(In thousands)	
Consolidated capital expenditures:			
Consolidated Statements of Cash Flows - Investing activities:			
Oil and gas assets	$ 377,491	$ 340,217	$ 213,806
Other property	2,102	11,796	7,935
Adjustments:			
Changes in capital accruals	(42,315)	33,717	26,669
Exploration expense, excluding unsuccessful well costs and leasehold impairments(1)	61,459	93,142	178,293
Capitalized interest	(25,013)	(28,077)	(28,331)
Proceeds on sale of assets	(99,337)	(16,713)	(13,703)
Other	(408)	6,654	765
Total consolidated capital expenditures	$ 273,979	$ 440,736	$ 385,434

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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, 2020, 2019 and 2018. 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.

	Ghana	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Total Oil	Ghana	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Total Gas	Kosmos Total	Equity Method Investment-Equatorial Guinea	Total
	Oil, Condensate, NGLs (MMBbls)					Natural Gas (Bcf)					(MMBoe)		
Net proved developed and undeveloped reserves at December 31, 2017(1)	82	—	—	—	82	49	—	—	—	49	89	21	110
Extensions and discoveries	—	—	—	—	—	—	—	—	—	—	—	—	—
Production	(11)	—	—	(2)	(13)	(1)	—	—	(2)	(3)	(14)	(5)	(19)
Revision in estimate	11	—	—	—	11	(1)	—	—	—	(1)	11	10	21
Purchases of minerals-in-place(2)	—	—	—	47	47	—	—	—	40	40	54	—	54
Net proved developed and undeveloped reserves at December 31, 2018(1)	82	—	—	45	127	47	—	—	38	85	141	26	166
Extensions and discoveries	—	—	—	—	—	—	—	—	—	—	—	—	—
Production	(11)	(4)	—	(8)	(23)	(1)	—	—	(6)	(7)	(24)	—	(24)
Revision in estimate(3)	17	6	—	3	26	(1)	(2)	—	3	—	26	—	26
Purchases of minerals-in-place(4)		24	—		24		14	—		14	26	(26)	—
Net proved developed and undeveloped reserves at December 31, 2019(1)	88	26	—	40	154	45	12	—	35	92	169	—	169
Extensions and discoveries	—	—	—		—	—	—	600	—	600	100	—	100
Production	(10)	(4)	—	(7)	(21)	—	—	—	(6)	(6)	(22)	—	(22)
Revision in estimate	(10)	2	—	2	(6)	(14)	(1)	(600)	(2)	(617)	(109)	—	(109)
Purchases of minerals-in-place	—	—	—	—	—	—	—	—	—	—	—	—	—
Net proved developed and undeveloped reserves at December 31, 2020(1)	68	24	—	34	127	31	11	—	27	69	139	—	139
Proved developed reserves(1)													
December 31, 2017	59	—	—	—	59	38	—	—	—	38	65	20	85
December 31, 2018	48	—	—	33	81	33	—	—	24	57	91	25	116
December 31, 2019	47	23	—	34	104	31	12	—	28	71	116	—	116
December 31, 2020	26	21	—	32	79	23	11	—	25	60	89	—	89
Proved undeveloped reserves(1)													
December 31, 2017	23	—	—	—	23	11	—	—	—	11	24	1	25
December 31, 2018	33	—	—	12	45	14	—	—	13	28	50	1	51
December 31, 2019	41	3	—	6	50	14	—	—	7	21	53	—	53
December 31, 2020	42	4	—	2	48	8	—	—	2	10	50	—	50

(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 purchase of minerals in place is related to the DGE acquisition completed in September 2018.

(3) The increase in proved reserves is a result of an increase of 8.2 MMBbl in Greater Jubilee related to positive drilling results and subsequent increased original oil in place, and optimized development plan. Changes at TEN include a positive revision of 8.8 MMBoe related to original oil in place adjustments based on the latest static modeling, and development plan updates. Changes at Equatorial Guinea include an increase of 6.3 MMBbl due to production optimization and plans for new drilling. Changes at the Gulf of Mexico (GoM) include an increase of 2.9 MMBoe related to strong performance of certain fields and the Gladden Deep discovery.

(4) We disclosed our share of reserves that were accounted for by the equity method. Effective of January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.4% undivided participating interest in the Ceiba Field and Okume Complex. As a result, our interest in the Ceiba Field and Okume Complex is accounted for under the proportionate consolidation method of accounting going forward.

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 2020. 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	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Other(1)	Kosmos Total
			(In millions)			
As of December 31, 2020						
Unproved properties	$ —	$ 125	$ 160	$ 196	$ 14	$ 495
Proved properties	3,288	421	421	1,240	—	5,370
	3,288	546	581	1,436	14	5,865
Accumulated depletion	(1,995)	(120)	—	(440)	—	(2,555)
Net capitalized costs	$ 1,293	$ 426	$ 581	$ 996	$ 14	$ 3,310
As of December 31, 2019						
Unproved properties	$ —	$ 119	$ 439	$ 233	$ 23	$ 814
Proved properties	3,250	411	—	1,244	—	4,905
	3,250	530	439	1,477	23	5,719
Accumulated depletion	(1,763)	(66)	—	(265)	—	(2,094)
Net capitalized costs	$ 1,487	$ 464	$ 439	$ 1,212	$ 23	$ 3,625

(1) Includes Africa (excluding Ghana, Equatorial Guinea, Mauritania and Senegal) and South America.

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	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Other(1)	Kosmos Total	Equity Method Investment-Equatorial Guinea(2)	Total
				(In millions)				
Year ended December 31, 2020								
Property acquisition:								
Unproved	$ —	$ —	$ —	$ 5	$ (1)	$ 4	$ —	$ 4
Proved	—	(2)	—	—	—	(2)	—	(2)
Exploration	—	7	21	34	34	96	—	96
Development	39	20	129	99	—	287	—	287
Total costs incurred	$ 39	$ 25	$ 150	$ 138	$ 33	$ 385	$ —	$ 385
Year ended December 31, 2019								
Property acquisition:								
Unproved	$ —	$ 11	$ 2	$ 15	$ —	$ 28	$ —	$ 28
Proved	—	—	—	—	—	—	—	—
Exploration	—	41	26	122	38	227	—	227
Development	59	126	11	91	—	287	—	287
Total costs incurred	$ 59	$ 178	$ 39	$ 228	$ 38	$ 542	$ —	$ 542
Year ended December 31, 2018								
Property acquisition:								
Unproved	$ —	$ 2	$ —	$ 303	$ 1	$ 306	$ —	$ 306
Proved(3)	—	—	—	1,038	—	1,038	—	1,038
Exploration	3	30	33	69	137	272	—	272
Development	111	—	4	21	—	136	—	136
Total costs incurred	$ 114	$ 32	$ 37	$ 1,431	$ 138	$ 1,752	$ —	$ 1,752

(1) Includes Africa (excluding Ghana, Equatorial Guinea, Mauritania and Senegal), 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 2020. 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.

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	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Equity Method Investment-Equatorial Guinea	Total
	(In millions)					
At December 31, 2020						
Future cash inflows	$ 2,791	$ 986	$ —	$ 1,244	$ —	$ 5,021
Future production costs	(1,197)	(577)	—	(249)	—	(2,023)
Future development costs	(765)	(352)	—	(306)	—	(1,423)
Future tax expenses	(251)	(131)	—	(7)	—	(389)
Future net cash flows	578	(74)	—	682	—	1,186
10% annual discount for estimated timing of cash flows	(214)	101	—	(109)	—	(222)
Standardized measure of discounted future net cash flows	$ 364	$ 27	$ —	$ 573	$ —	$ 964
At December 31, 2019						
Future cash inflows	$ 5,546	$ 1,650	$ —	$ 2,205	$ —	$ 9,401
Future production costs	(1,683)	(675)	—	(312)	—	(2,670)
Future development costs	(736)	(400)	—	(393)	—	(1,529)
Future tax expenses	(1,026)	(317)	—	(123)	—	(1,466)
Future net cash flows	2,101	258	—	1,377	—	3,736
10% annual discount for estimated timing of cash flows	(675)	36	—	(278)	—	(917)
Standardized measure of discounted future net cash flows	$ 1,426	$ 294	$ —	$ 1,099	$ —	$ 2,819
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

Changes in the Standardized Measure for Discounted Cash Flows

	Ghana	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Equity Method Investment-Equatorial Guinea	Total
			(In millions)			
Balance at December 31, 2017	$ 971	$ —	$ —	$ —	$ 130	$ 1,101
Purchase of minerals in place(1)	—	—	—	1,487	—	1,487
Sales and transfers 2018	(545)	—	—	(117)	(287)	(949)
Extensions and discoveries	—	—	—	—	—	—
Net changes in prices and costs	1,137	—	—	—	271	1,408
Previously estimated development costs incurred during the period	105	—	—	—	—	105
Net changes in development costs	15	—	—	—	(29)	(14)
Revisions of previous quantity estimates	398	—	—	—	385	783
Net changes in tax expenses	(565)	—	—	—	(136)	(701)
Accretion of discount	112	—	—	—	30	142
Changes in timing and other	(88)	—	—	—	27	(61)
Balance at December 31, 2018	$ 1,540	$ —	$ —	$ 1,370	$ 391	$ 3,301
Purchase of minerals in place	—	391	—	—	(391)	—
Sales and transfers 2019	(568)	(210)	—	(336)	—	(1,114)
Extensions and discoveries	—	—	—	(14)	—	(14)
Net changes in prices and costs	(352)	(151)	—	(401)	—	(904)
Previously estimated development costs incurred during the period	97	11	—	109	—	217
Net changes in development costs	44	(57)	—	(43)	—	(56)
Revisions of previous quantity estimates	474	187	—	109	—	770
Net changes in tax expenses	(23)	11	—	231	—	219
Accretion of discount	224	69	—	167	—	460
Changes in timing and other	(10)	43	—	(93)	—	(60)
Balance at December 31, 2019	$ 1,426	$ 294	$ —	$ 1,099	$ —	$ 2,819
Purchase of minerals in place	—	—	—	—	—	—
Sales and transfers 2020	(197)	(72)	—	(197)	—	(466)
Extensions and discoveries	—	—	80	—	—	80
Net changes in prices and costs	(1,292)	(390)	(80)	(633)	—	(2,395)
Previously estimated development costs incurred during the period	44	33	—	126	—	203
Net changes in development costs	(65)	(19)	—	(57)	—	(141)
Revisions of previous quantity estimates	(95)	27	—	44	—	(24)
Net changes in tax expenses	440	88	—	81	—	609
Accretion of discount	212	52	—	118	—	382
Changes in timing and other	(109)	14	—	(8)	—	(103)
Balance at December 31, 2020	$ 364	$ 27	$ —	$ 573	$ —	$ 964

(1) We disclosed our share of reserves that were accounted for by the equity method. Effective of January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.4% undivided participating interest in the Ceiba Field and Okume Complex. As a result, our interest in the Ceiba Field and Okume Complex is accounted for under the proportionate consolidation method of accounting going forward.

KOSMOS ENERGY LTD.

Supplemental Quarterly Financial Information (Unaudited)

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
	(In thousands, except per share data)			
2020				
Revenues and other income	$ 177,781	$ 127,314	$ 224,787	$ 366,316
Costs and expenses	295,005	374,130	261,279	382,579
Net income (loss)	(182,767)	(199,391)	(37,384)	7,956
Net income (loss) per share:				
Basic(1)	(0.45)	(0.49)	(0.09)	0.02
Diluted(1)	(0.45)	(0.49)	(0.09)	0.02
2019				
Revenues and other income	$ 296,790	$ 395,934	$ 356,970	$ 460,215
Costs and expenses	358,370	346,495	317,435	462,492
Net income (loss)	(52,906)	16,837	16,065	(35,773)
Net income (loss) per share:				
Basic(1)	(0.13)	0.04	0.04	(0.09)
Diluted(1)	(0.13)	0.04	0.04	(0.09)

(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.

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, 2020, in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, including that such information is accumulated and communicated to the Company's management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosure.

Evaluation of Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during our most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control has been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles. All internal control systems have inherent limitations, including the possibility of human error and the possible circumvention of or overriding of controls. The design of an internal control system is also based in part upon assumptions and judgments made by management. As a result, even an effective system of internal controls can provide no more than reasonable assurance with respect to the fair presentation of financial statements and the processes under which they were prepared. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that internal control may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of the end of the period covered by this report based on the framework in "Internal Control—Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, our Chief Executive Officer and our Chief Financial Officer concluded that our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

Ernst & Young LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this annual report on Form 10-K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2020 which is included in "Item 8. Financial Statements and Supplementary Data."

Item 9B. Other Information

Disclosures Required Pursuant to Section 13(r) of the Securities Exchange Act of 1934

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the 2021 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2020.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2021 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2020.

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 2021 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2020.

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

The information required by this item is incorporated herein by reference to the 2021 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2020.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2021 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2020.

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 2020, 2019 and 2018 (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.

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY BALANCE SHEETS

(In thousands, except share data)

	December 31, 2020	December 31, 2019
Assets		
Current assets:		
Cash and cash equivalents	$ 1,166	$ 6,422
Receivables from subsidiaries	—	3,819
Prepaid expenses and other	908	428
Derivatives—related party	2,502	—
Total current assets	4,576	10,669
Investment in subsidiaries at equity	1,034,226	1,159,560
Long-term note receivable from subsidiary	176,540	518,844
Deferred financing costs, net of accumulated amortization of $17,296 and $14,681 at December 31, 2020 and December 31, 2019, respectively	3,706	6,321
Derivatives—related party	140	—
Restricted cash	305	305
Long-term deferred tax asset	18,687	17,265
Total assets	$ 1,238,180	$ 1,712,964
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable	$ 153	$ —
Accounts payable to subsidiaries	38,558	—
Accrued liabilities	14,157	11,942
Derivatives	2,502	—
Total current liabilities	55,370	11,942
Long-term debt, net	741,606	640,856
Long-term note payable to subsidiary	—	217,000
Derivatives	140	—
Other long-term liabilities	910	1,464
Shareholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2020 and December 31, 2019	—	—
Common stock, $0.01 par value; 2,000,000,000 authorized shares; 449,718,317 and 445,779,367 issued at December 31, 2020 and December 31, 2019, respectively	4,497	4,458
Additional paid-in capital	2,307,220	2,297,221
Accumulated deficit	(1,634,556)	(1,222,970)
Treasury stock, at cost, 44,263,269 shares at December 31, 2020 and 2019, respectively	(237,007)	(237,007)
Total shareholders' equity	440,154	841,702
Total liabilities and shareholders' equity	$ 1,238,180	$ 1,712,964

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY STATEMENTS OF OPERATIONS

(In thousands)

	Years Ended December 31,		
	2020	2019	2018
Revenues and other income:			
Oil and gas revenue	$ —	$ —	$ —
Other income—related party	2,642	—	—
Total revenues and other income	2,642	—	—
Costs and expenses:			
General and administrative	40,162	40,840	47,279
General and administrative recoveries—related party	4,112	(30,822)	(36,197)
Interest and other financing costs, net	59,200	86,104	66,055
Interest and other financing costs, net—related party	(5,889)	(7,144)	(7,941)
Derivatives, net	2,642	—	—
Other expenses, net	—	10	49
Equity in (earnings) losses of subsidiaries	315,423	(15,064)	23,614
Total costs and expenses	415,650	73,924	92,859
Loss before income taxes	(413,008)	(73,924)	(92,859)
Income tax expense	(1,422)	(18,147)	1,132
Net loss	$ (411,586)	$ (55,777)	$ (93,991)
Dividends declared per common share	$ 0.0452	$ 0.1808	$ —

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2020	2019	2018
Operating activities			
Net loss	$ (411,586)	$ (55,777)	$ (93,991)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Equity in (earnings) losses of subsidiaries	315,423	(15,064)	23,614
Equity-based compensation	32,706	32,370	35,230
Depreciation and amortization	8,644	5,039	7,292
Deferred income taxes	(1,422)	(18,397)	1,132
Other income—related party	(2,642)	—	—
Change in fair value on derivatives	2,642	—	—
Loss on extinguishment of debt	—	22,913	—
Other	—	—	268
Changes in assets and liabilities:			
Decrease in receivables	856	427	1,234
(Increase) decrease in prepaid expenses and other	(480)	(115)	(23)
(Increase) decrease due to/from related party	162,897	43,974	(42,163)
Increase (decrease) in accounts payable and accrued liabilities	2,509	(8,754)	816
Net cash provided by (used in) operating activities	109,547	6,616	(66,591)
Investing activities			
Investment in subsidiaries	(190,089)	287,972	(36,192)
Net cash provided by (used in) investing activities	(190,089)	287,972	(36,192)
Financing activities			
Borrowings under long-term debt	100,000	—	400,000
Payments on long-term debt	—	(325,000)	(75,000)
Net proceeds from issuance of senior notes	—	641,875	—
Redemption of senior secured notes	—	(535,338)	—
Purchase of treasury stock / tax withholdings	(4,947)	(1,983)	(206,051)
Dividends	(19,271)	(72,599)	—
Deferred financing costs	(496)	(1,897)	(9,382)
Net cash provided by (used in) financing activities	75,286	(294,942)	109,567
Net increase (decrease) in cash and cash equivalents	(5,256)	(354)	6,784
Cash, cash equivalents and restricted cash at beginning of period	6,727	7,081	297
Cash, cash equivalents and restricted cash at end of period	$ 1,471	$ 6,727	$ 7,081
Non-cash activity:			
Issuance of common stock for related party receivable	$ —	$ —	$ 307,944

Schedule II

Kosmos Energy Ltd.

Valuation and Qualifying Accounts

For the Years Ended December 31, 2020, 2019 and 2018

Description	Balance January 1,	Additions: Charged to Costs and Expenses	Additions: Charged To Other Accounts	Deductions From Reserves	Balance December 31,
2020					
Allowance for credit losses	$ 2,748	$ 1,800	$ 1,127	$ —	$ 5,675
Allowance for deferred tax assets	$ 201,749	$ 86,539	$ —	$ —	$ 288,288
2019					
Allowance for doubtful receivables	$ 1,211	$ 1,324	$ 228	$ (15)	$ 2,748
Allowance for deferred tax assets	$ 156,860	$ 44,889	$ —	$ —	$ 201,749
2018					
Allowance for doubtful receivables	$ —	$ 1,211	$ —	$ —	$ 1,211
Allowance for deferred tax assets	$ 93,525	$ 63,335	$ —	$ —	$ 156,860

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

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 23, 2021

By: /s/ NEAL D. SHAH
Neal D. Shah
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 23, 2021
/s/ NEAL D. SHAH Neal D. Shah	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 23, 2021
/s/ RONALD GLASS Ronald Glass	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 23, 2021
/s/ LISA DAVIS Lisa Davis	Director	February 23, 2021
/s/ SIR RICHARD B. DEARLOVE Sir Richard B. Dearlove	Director	February 23, 2021
/s/ DEANNA L. GOODWIN Deanna L. Goodwin	Director	February 23, 2021
/s/ ADEBAYO O. OGUNLESI Adebayo O. Ogunlesi	Director	February 23, 2021
/s/ STEVEN M. STERIN Steven M. Sterin	Director	February 23, 2021

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).
4.2	Description of the Company's Capital Stock (filed as Exhibit 4.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2019, 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).

Exhibit Number	Description of Document
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).
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).

Exhibit Number	Description of Document
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 for the year ended December 31, 2016, and incorporated herein by reference).
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).

Exhibit Number	Description of Document
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).
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 (filed as Exhibit 10.42 to the Company's Annual Report on Form 10-K of the year ended December 31, 2018, and incorporated herein by reference).
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 (filed as Exhibit 10.43 to the Company's Annual Report on Form 10-K of the year ended December 31, 2018, and incorporated herein by reference).
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 (filed as Exhibit 10.44 to the Company's Annual Report on Form 10-K of the year ended December 31, 2018, and incorporated herein by reference).
	South Africa
10.45	Exploration Right Contract relating to the Northern Cape Ultra Deep Block Offshore South Africa between the Republic of South Africa and OK Energy Limited dated January 10, 2019 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2019, and incorporated herein by reference).
	Greater Tortue Ahmeyim
10.46† †	Agreement for a Long Term Sale and Purchase of LNG, dated February 11, 2020, between LA Societe Mauritanienne des Hydrocarbures et de Patrimoine Minier, BP Mauritania Investments Limited, Kosmos Energy Investments Limited, La Societe des Petroles du Senegal, BP Senegal Investments Limited, Kosmos Energy Investments Senegal Limited and BP Gas Marketing Limited (filed as Exhibit 10.46 to the Company's Annual Report on Form 10-K for the year ended December 31, 2019, and incorporated herein by reference).
	Financing Agreements
10.47	Indenture, dated as of April 4, 2019, among the Company, the guarantors names therein, 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 April 4, 2019 (File No. 001-35167), and incorporated herein by reference).
10.48	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).
10.49	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).
10.50††	Prepayment Agreement dated June 26, 2020 between Kosmos Energy Gulf of Mexico Operations, LLC and Trafigura Trading LLC (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020, and incorporated herein by reference).

Exhibit Number	Description of Document
10.51† †	Senior Secured Term Loan Credit Agreement, dated September 30, 2020, among Kosmos Energy Ltd., Kosmos Energy GoM Holdings, LLC, Kosmos Energy Gulf of Mexico Operations, LLC, the Other Guarantors named therein, the Initial Lenders named therein and CLMG CORP, as Term Loan Collateral Agent and Administrative Agent (filed as Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020, and incorporated herein by reference).
	Agreements with Shareholders and Directors
10.52	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).
10.53	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").
10.54	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).
10.55	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).
10.56	Amendment No. 1 to the Registration Rights Agreement, dated as of February 8, 2013, among Kosmos Energy Ltd. and the other parties signatory thereto (filed as Exhibit 10.34 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference).
	Management Contracts/Compensatory Plans or Arrangements
10.57†	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).
10.58†	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).
10.59†	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).
10.60†	Long Term Incentive Plan (amended and restated as of March 27, 2018) (filed as Exhibit 99 to the Company's Registration Statement on Form S-8 filed November 15, 2018 (File No. 333-207259), and incorporated herein by reference).
10.61†	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).
10.62†	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).
10.63†	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).
10.64†	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).
10.65†	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).
10.66†	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).
10.67†	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).
10.68†	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).
10.69†	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).
10.70†	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).

Exhibit Number	Description of Document
10.71†	Exit Agreement between Kosmos Energy, LLC and Brian F. Maxted dated March 1, 2019 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2019, and incorporated herein by reference).
10.72†	Offer Letter between Kosmos Energy Gulf of Mexico, LLC and Richard R. Clark dated August 3, 2018 (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2019, and incorporated herein by reference).
10.73†	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).
10.74†	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).
10.75†	Offer Letter, dated November 12, 2019, between Kosmos Energy, LLC and Ronald Glass (filed as Exhibit 10.73 to the Company's Annual Report on Form 10-K for the year ended December 31, 2019, and incorporated herein by reference).
10.76†	Offer Letter, dated November 12, 2019, between Kosmos Energy, LLC and Neal D. Shah (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020, and incorporated herein by reference).
10.77†	Kosmos Energy Deferred Compensation Plan (effective February 1, 2017) (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017, and incorporated herein by reference).
	DGE Acquisition
10.78	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
10.79††	Asset Sale Agreement related to Blocks 3013 and 3113 (North Cape Ultra Deep) offshore South Africa, dated September 8, 2020, between Shell Offshore Upstream South Africa B.V. and Kosmos Energy South Africa Limited (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020, and incorporated herein by reference).
10.80††	Share Sale and Purchase Agreement related to the sale and purchase of shares of KE Namibia Company, KE STP Company, and KE Suriname Company, dated September 8, 2020, between Kosmos Energy Operating, Kosmos Energy Holdings and B.V. Dordtsche Petroleum Maatschappij (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020, and incorporated herein by reference).
10.81††	Portfolio Agreement, dated September 8, 2020, between Kosmos Energy Operating and B.V. Dordtsche Petroleum Maatschappij (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020, and incorporated herein by reference).
10.82	Parent Guarantee Agreement, dated September 30, 2020, between Kosmos Energy Ltd. and CLMG CORP. related to the Senior Secured Term Loan Credit Agreement, dated September 30, 2020, among Kosmos Energy Ltd., Kosmos Energy GoM Holdings, LLC, Kosmos Energy Gulf of Mexico Operations, LLC and CLMG CORP (filed as Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020, and incorporated herein by reference).
14.1	Code of Business Conduct and Ethics (filed as Exhibit 14.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011, and incorporated herein by reference).
21.1*	List of Subsidiaries.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Ryder Scott Company, L.P.
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of Ryder Scott Company, L.P. - Ghana, Equatorial Guinea, U.S. Gulf of Mexico
101.INS*	XBRL Instance Document.

Exhibit Number	Description of 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.

† † Certain confidential portions of this Exhibit have been omitted pursuant to Item 601(b) of Regulation S-K because the identified confidential portions (i) are not material and (ii) would be competitively harmful if publicly disclosed.

Exhibit 21.1

List of Subsidiaries

Subsidiary	**Jurisdiction of Incorporation**
Kosmos Energy Ltd.	Delaware
Kosmos Energy Delaware Holdings, LLC	Delaware
Kosmos Energy Holdings	Cayman Islands
Kosmos Energy LLC	Texas
Kosmos Energy Operating	Cayman Islands
Kosmos Energy Ventures	Cayman Islands
Kosmos Energy South Atlantic	Cayman Islands
Kosmos Energy Latin America	Cayman Islands
Kosmos Energy Deepwater Morocco	Cayman Islands
Kosmos Energy Offshore Morocco HC	Cayman Islands
Kosmos Energy Finance International	Cayman Islands
Kosmos Energy International	Cayman Islands
Kosmos Energy Development	Cayman Islands
Kosmos Energy Ghana HC	Cayman Islands
Kosmos Energy Suriname	Cayman Islands
Kosmos Energy Mauritania	Cayman Islands
Kosmos Energy Venture Holdings	Cayman Islands
Kosmos Energy Equatorial Guinea	Cayman Islands
Kosmos Energy Credit International	Cayman Islands
FATE Energy Services	Cayman Islands
Kosmos Energy Portugal	Cayman Islands
Kosmos Energy Senegal	Cayman Islands
Kosmos Energy Global Supply	Cayman Islands
Kosmos Energy Sao Tome and Principe	Cayman Islands
Kosmos Energy Sao Tome and Principe Block 4	Cayman Islands
Kosmos Energy Maroc Mer Profonde	Cayman Islands
Kosmos Energy Congo	Cayman Islands
Kosmos Energy Cote d’Ivoire	Cayman Islands
Kosmos Energy Namibia	Cayman Islands
Kosmos Energy GOM Holdings, LLC	United States of America
Kosmos Energy Gulf of Mexico, LLC	United States of America
Kosmos Energy Gulf of Mexico Management, LLC	United States of America
Kosmos Energy Gulf of Mexico Operations, LLC	United States of America
Houston Energy Deepwater Ventures	United States of America
Kosmos Energy Investments Senegal Limited	United Kingdom
Kosmos International Petroleum, Inc.	Cayman Islands
Kosmos Equatorial Guinea, Inc.	Cayman Islands
Kosmos Energy South Africa Limited	United Kingdom
Kosmos Energy Tortue Finance	Cayman Islands
Kosmos Energy Offshore South Africa	Mauritius
Kosmos Energy Portfolio Limited	United Kingdom

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statements (Form S-8, No. 333-174234, Form S-8, No. 333-207259 and Form S-8, No. 333-228397) pertaining to the Kosmos Energy Ltd. Long Term Incentive Plan and the Registration Statements (Form S-3, No. 333-230284 and Form S-3, No. 333-227084) of Kosmos Energy Ltd. and in the related Prospectus of our reports dated February 23, 2021, with respect to the consolidated financial statements and schedules and the effectiveness of internal control over financial reporting of Kosmos Energy Ltd., included in this Annual Report (Form 10-K) for the year ended December 31, 2020.

/s/ Ernst & Young LLP

Dallas, Texas
February 23, 2021

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

EXHIBIT 23.2

February 22, 2021

Mr. Paul Tooms
Kosmos Energy, LLC
8176 Park Lane, Suite 500
Dallas, Texas 75231

We hereby consent to (1) the reference of our firm and to the use of our reports of the Greater Jubilee, TEN, Ceiba, Okume, and Gulf of Mexico Project Area effective December 31, 2020 and dated January 22, 2021, in the Kosmos Energy Ltd. Annual Report on Form 10K for the year ended December 31, 2020, to be filed with the U.S. Securities Exchange Commission on or about February 22, 2021; and (2) the incorporation by reference of our reports of the Greater Jubilee, TEN, Ceiba, Okume, and Gulf of Mexico Project Area effective December 31, 2020 and dated January 22, 2021 in the Kosmos Energy Ltd. Registration Statements (Form S8, No. 333174234, Form S-8, No. 333-207259 and Form S-8, No. 333-228397) and Registration Statements (Form S3, No. 333227084 and Form S-3, No. 333-230824) and in any related prospectus, including any reference to our firm under the heading "Experts" in such prospectus.

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

SUITE 2800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799
633 17TH STREET, SUITE 1700 DENVER, COLORADO 80202 TEL (303) 339-8110

Exhibit 31.1

Certification of Chief Executive Officer

I, Andrew G. Inglis, certify that:

1. I have reviewed this annual report on Form 10-K of Kosmos Energy Ltd.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2021

/s/ ANDREW G. INGLIS

Andrew G. Inglis
Chairman of the Board of Directors and
Chief Executive Officer (Principal Executive Officer)

Exhibit 31.2

Certification of Chief Financial Officer

I, Neal D. Shah, certify that:

1. I have reviewed this annual report on Form 10-K of Kosmos Energy Ltd.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2021

/s/ NEAL D. SHAH

Neal D. Shah
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

Certification of Chief Executive Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the accompanying annual report of Kosmos Energy Ltd. (the "Company") on Form 10-K for the period ended December 31, 2020, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Andrew G. Inglis, Chairman of the Board of Directors and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 23, 2021	/s/ ANDREW G. INGLIS
	Andrew G. Inglis *Chairman of the Board of Directors and Chief Executive Officer* *(Principal Executive Officer)*

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

Certification of Chief Financial Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the annual report of Kosmos Energy Ltd. (the "Company") on Form 10-K for the period ended December 31, 2020, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Neal D. Shah, Senior Vice President and Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 23, 2021	/s/ NEAL D. SHAH
	Neal D. Shah *Senior Vice President and Chief Financial Officer* *(Principal Financial Officer)*

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 99.1

KOSMOS ENERGY LIMITED

Estimated

Future Reserves and Income

Attributable to Certain Interests

Proved Reserves

SEC Parameters

As of

December 31, 2020

/s/ Tosin Famurewa
Tosin Famurewa, P.E., S.P.E.C.
TBPE License No. 100569
Managing Senior Vice President

[SEAL]

/s/ Christine E. Neylon
Christine E. Neylon, P.E.
TBPE License No. 122128
Vice President

/s/ Victor Abu
Victor Abu, P.E.
TBPE License No. 132717
Vice President

[SEAL] **[SEAL]**

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COM
PETROLEUM CONSUL

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 22, 2021

Kosmos Energy Limited
8176 Park Lane, Suite 500
Dallas, Texas 75231

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain interests of Kosmos Energy Limited (Kosmos) as of December 31, 2020. The subject properties are located in Ghana, offshore West Africa, in the West Cape Three Points (WCTP) and Deep Water Tano (DWT) blocks, hereafter referred to as the "Greater Jubilee and TEN Project Areas," Equatorial Guinea, offshore Central Africa, in the G and F blocks, hereafter referred to as the "Ceiba and Okume Project Areas" and United States of America, federal waters offshore Louisiana and Texas, hereafter referred to as the "Gulf of Mexico Project Area." The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 17, 2021 and presented herein, was prepared for public disclosure by Kosmos in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott in this report represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Kosmos as of December 31, 2020.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2020, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. At Kosmos' request, we have included estimated gross (100%) reserves, along with the estimated net reserves and income data. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Gross Reserves* Data
Derived Through Certain Interests of
Kosmos Energy Limited
As of December 31, 2020

	Proved			
	Developed			
	Producing	Non-Producing	Undeveloped	Total
Gulf of Mexico Project Area				
Gross Reserves				
Oil/Condensate – Mbbl	106,331	23,042	16,702	146,075
Plant Products – MBOE	9,707	3,686	916	14,309
Produced Gas – MMcf	112,983	41,455	12,463	166,901
Fuel Gas – MMcf	0	0	0	0
Greater Jubilee and TEN Project Areas				
Gross Reserves				
Oil/Condensate – Mbbl	128,991	0	207,752	336,743
Plant Products – MBOE	0	0	0	0
Produced Gas – MMcf	498,290	0	393,448	891,738
Fuel Gas – MMcf	68,759	0	0	68,759
Ceiba and Okume Project Areas				
Gross Reserves				
Oil/Condensate – Mbbl	49,365	10,997	10,276	70,638
Plant Products – MBOE	0	0	0	0
Produced Gas – MMcf	29,010	9,015	5,673	43,698
Fuel Gas – MMcf	26,953	0	0	26,953
Total				
Gross Reserves				
Oil/Condensate – Mbbl	284,687	34,039	234,730	553,456
Plant Products – MBOE	9,707	3,686	916	14,309
Produced Gas – MMcf	640,283	50,470	411,584	1,102,337
Fuel Gas – MMcf	95,712	0	0	95,712

**These volumes are 100% gross and do not represent net volumes to Kosmos' interests. Net reserves and income are shown below.*

SEC PARAMETERS
Estimated Net Reserves and Income Data
Derived Through Certain Interests of
Kosmos Energy Limited
As of December 31, 2020

	Proved			
	Developed			
	Producing**	Non-Producing	Undeveloped	Total
Gulf of Mexico Project Area				
Net Reserves				
Oil/Condensate – Mbbl	23,770	5,710	2,179	31,659
Plant Products – MBOE	1,936	633	157	2,726
Sales Gas – MMcf	19,063	6,296	1,972	27,331
Fuel Gas – MMcf	0	0	0	0
Income Data ($M)				
Future Gross Revenue	$931,282	$231,585	$80,710	$1,243,577
Deductions	338,487	165,609	50,559	554,655
Future Net Income (FNI)	$592,795	$ 65,976	$30,151	$ 688,922
Discounted FNI @ 10%	$516,184	$ 41,666	$21,090	$ 578,940
Greater Jubilee and TEN Project Areas				
Net Reserves				
Oil/Condensate – Mbbl	26,010	0	42,242	68,252
Plant Products – MBOE	0	0	0	0
Sales Gas – MMcf	9,336	0	7,933	17,269
Fuel Gas – MMcf	14,020	0	0	14,020
Income Data ($M)				
Future Gross Revenue	$1,069,417	$0	$1,732,596	$2,802,013
Deductions	599,246	0	1,367,940	1,967,186
Future Net Income (FNI)	$ 470,171	$0	$ 364,656	$ 834,827
Discounted FNI @ 10%	$ 367,630	$0	$ 169,208	$ 536,838

Ceiba and Okume Project Areas

Net Reserves				
Oil/Condensate – Mbbl	16,864	3,753	3,576	24,193
Plant Products – MBOE	0	0	0	0
Sales Gas – MMcf	0	0	0	0
Fuel Gas – MMcf	11,455	0	0	11,455
Income Data ($M)				
Future Gross Revenue	$685,099	$152,448	$145,263	$982,810
Deductions	604,881	167,379	154,818	927,078
Future Net Income (FNI)	$ 80,218	$ (14,931)	$ (9,555)	$ 55,732
Discounted FNI @ 10%	$120,537	$ 8,448	$ (6,467)	$122,518

Total

Net Reserves				
Oil/Condensate – Mbbl	66,644	9,463	47,997	124,104
Plant Products – MBOE	1,936	633	157	2,726
Sales Gas – MMcf	28,399	6,296	9,905	44,600
Fuel Gas – MMcf	25,475	0	0	25,475
Income Data ($M)				
Future Gross Revenue	$2,685,798	$384,033	$1,958,569	$5,028,400
Deductions	1,542,614	332,988	1,573,317	3,448,919
Future Net Income (FNI)	$1,143,184	$ 51,045	$ 385,252	$1,579,481
Discounted FNI @ 10%	$1,004,351	$ 50,114	$ 183,831	$1,238,296

***Includes proved depleted summary consisting of certain P&A liability costs*

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). Fuel gas volumes are attributed to those volumes of gas that are consumed for fuel in field operations, while sales gas volumes are reported on an “as sold basis.” Kosmos elected not to report fuel gas for the Gulf of Mexico Project Area. All gas volumes are expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package PHDWin Petroleum Economic Evaluation Software, a copyrighted program of TRC Consultants L.C. and economic models developed in Microsoft EXCEL. These programs were used at the request of Kosmos. Ryder Scott has found these programs to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The deductions incorporate the normal direct costs of operating the wells, recompletion costs, development costs, and certain abandonment costs net of salvage. Deductions in the Greater Jubilee and TEN project areas include Additional Oil Entitlements (“AOE”). AOE is a contractual mechanism that prevents the contractor group from collecting “windfall profits” and is treated herein as a deduction to the future gross revenue; however, for the Greater Jubilee and TEN Project Areas our economic analysis indicates there are no AOE deductions for the proved reserves. The AOE calculation is determined at the block level and includes a rate of return calculation that is derived on an after corporate income tax basis based on interpretations of tax considerations made by Kosmos. In the Greater Jubilee and TEN Project Areas, abandonment costs (included in the “Development Costs” column of the cash flow projections) are triggered and escrowed several years before the economic limit is reached, and this may result in negative FNI values for certain years prior to abandonment.

Certain gas, oil and condensate processing and handling fees, including compression fees where applicable are included as “Other” and “Ad Valorem Taxes” deductions in the cash flows. The later are not true ad valorem taxes but represent Kosmos’ throughput fee to Talos for processing and handling of the production volumes from the Tornado field in the Gulf of Mexico Project Area. The separate tracking of this throughput fee in the “Ad Valorem Taxes” column of the cash flows was done at Kosmos’ request.

There are no production taxes associated with the Greater Jubilee, TEN, Ceiba, Okume and Gulf of Mexico Project Areas. The future net income is before the deductions of U.S. state and federal or foreign income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 99.2 percent and gas reserves account for the remaining 0.8 percent of the total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded annually. Future net income was discounted at four other discount rates which were also compounded annually. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2020
Discount Rate Percent	Total Proved
5	$1,396,329
15	$1,105,012
20	$ 993,450
25	$ 900,086

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission’s Regulations Part 210.4-10(a). An abridged version of the SEC reserves

definitions from 210.4-10(a) entitled “PETROLEUM RESERVES DEFINITIONS” is included as an attachment to this report.
The various reserves status categories are defined in the attachment entitled “PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES” in this report. The proved developed non-producing reserves included herein consist of the shut-in and behind pipe status categories.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist.

Reserves are “estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.” All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves, and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Kosmos’ request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are “those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward.” The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a “high degree of confidence that the quantities will be recovered.”

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

The proved reserves reported herein are limited to the period prior to expiration of current contracts providing the legal rights to produce, or a revenue interest in such production unless evidence indicates that contract renewal is reasonably certain. Furthermore, the subject properties located in Ghana and Equatorial Guinea may be subjected to substantially varying contractual fiscal terms that affect the net revenue to Kosmos for the production of these volumes. The prices and economic return received for these net volumes can vary materially based on the terms of these contracts. Therefore, when applicable, Ryder Scott reviewed the fiscal terms of such contracts and discussed with Kosmos the net economic benefit attributed to such operations for the determination of the net hydrocarbon volumes and income thereof. Ryder Scott has not conducted an exhaustive audit or verification of such contractual information. Neither our review of such contractual information nor our acceptance of Kosmos representations regarding such contractual information should be construed as a legal opinion on this matter.

Ryder Scott did not evaluate the country and geopolitical risks in the countries where Kosmos operates or has interests. Kosmos operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Kosmos owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, the volumetric method, analogy, or a combination of methods. Approximately 23 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. The performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation which utilized extrapolations of historical production and pressure data available through December 2020 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Kosmos and were considered sufficient for the purpose thereof. The remaining 77 percent of the proved producing reserves were estimated by the volumetric method, analogy, or a combination of methods. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserves estimates was considered to be inappropriate. However, available performance data were used to ensure the volumetric parameters in our estimates derived from the volumetric method were appropriate.

Approximately 1.2 percent of the proved developed non-producing reserves included herein were estimated by the performance method. The remaining 98.8 percent of the proved developed non-producing reserves and all of the proved undeveloped reserves for the properties included herein were estimated by a combination of the volumetric method, analogy and performance method. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by Kosmos or obtained from public data sources that were available through December 2020. The data utilized from the analogues as well as well and seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Kosmos has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Kosmos with respect to property interests owned, contractual terms that govern future net income, production and well tests from examined wells, normal direct costs of operating the wells or leases and all the required facilities such as the FPSO, other costs such as transportation and/or processing fees, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Kosmos. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If a decline trend has been established, this trend was used as the basis for estimating future production rates. If no production decline trend has been established, one of the following occurred:

- future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves.

- future production rates were projected based on a type well derived from analogy to surrounding historical well production.

- future production rates were based on a combination of historical performance data, volumetric analysis and a robust numerical simulation model. Future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated “simulation based decline rate” was then applied until depletion of the reserves.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Kosmos. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract.

Kosmos furnished us with the above mentioned average prices in effect on December 31, 2020. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, NGL processing fees, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by Kosmos. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Kosmos to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Price	Average Realized Price
West Africa				
Greater Jubilee and TEN Project Areas	Oil	Brent	$41.77/BBL	$40.90/BBL
	Gas	Contract	$0.60/MCF	$0.60/MCF
Central Africa				
Ceiba and Okume Project Areas	Oil	Brent	$41.77/BBL	$40.62/BBL
North America				
Gulf of Mexico Project Area	Oil/ Condensate	Heavy Louisiana Sweet	$40.51/BBL	$37.74/BBL
	NGLs	Heavy Louisiana Sweet	$40.51/BBL	$6.58/BBL
	Gas	Henry Hub	$1.99/MMBTU	$1.13/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the contract areas and wells in this report were furnished by Kosmos and are based on their operating expense reports and include only those costs directly applicable to the contract areas or wells. The operating costs include a portion of general and administrative costs allocated directly to the contract areas and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. Certain gas, oil and condensate processing and handling fees, including compression fees where applicable are included as "other" and "Ad Valorem Taxes" deductions in the cash flows. The later are not true ad valorem taxes but represent Kosmos' throughput fee to Talos for processing and handling of the production volumes from the Tornado field. The separate tracking of this throughput fee in the "Ad Valorem Taxes" column of the cash flows was done at Kosmos' request. For some Gulf of Mexico Project Area assets, we calculated their operating costs using Lease Operating Statements (LOE) provided by Kosmos. For the remaining assets, the operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Kosmos. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the contract areas or wells.

Development costs were furnished to us by Kosmos and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by Kosmos were accepted without independent verification. Kosmos advises that their contractual share of Mississippi Canyon 697/698/741/742 (Big Bend) field, in the Gulf of Mexico Project Area, Plug and Abandonment (P&A) liability is zero.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Kosmos' plans to develop these reserves as of December 31, 2020. The implementation of Kosmos' development plans as presented to us and incorporated herein is subject to the approval process adopted by Kosmos' management. As the result of our inquiries during the course of preparing this report, Kosmos has informed us that the development activities included herein have been subjected to and received the internal approvals required by Kosmos management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Kosmos. Kosmos has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Kosmos has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change or evolve from those under existing economic conditions as of December 31, 2020, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Kosmos were held constant throughout the life of the properties. However, in some contract areas, anticipated changes to operations during the field life-ramp-down, specifically consolidation of activates, reduced well count and/or fluid handling, and other synergies, are projected to result in certain cost reductions.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Kosmos Energy Limited. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Kosmos.

Kosmos makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Kosmos has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and S-8 of Kosmos Energy Limited of the references to our name as well as to the references to our third party report for Kosmos Energy Limited, which appears in the December 31, 2020 annual report on Form 10-K of Kosmos Energy Limited. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Kosmos Energy Limited.

We have provided Kosmos with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Kosmos and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Tosin Famurewa

Tosin Famurewa, P.E., S.P.E.C.
TBPE License No. 100569
Managing Senior Vice President **[SEAL]**

/s/ Christine E. Neylon

Christine E. Neylon, P.E.
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Vice President **[SEAL]**

/s/ Victor Abu

Victor Abu, P.E
TBPE License No. 132717
Vice President **[SEAL]**

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Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. (Ryder Scott). Tosin Famurewa was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott presented herein.

Mr. Famurewa, an employee of Ryder Scott since 2006, is a Managing Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Mr. Famurewa is also a member of Ryder Scott's Board of Directors. Before joining Ryder Scott, Mr. Famurewa served in a number of engineering positions with Chevron and Texaco. For more information regarding Mr. Famurewa's geographic and job specific experience, please refer to Ryder Scott's website at www.ryderscott.com/Experience/Employees.

Mr. Famurewa earned double Bachelor of Science degrees in Chemical Engineering and Material Science and Engineering from University of California at Berkeley in 2000 and a Master of Science degree in Petroleum Engineering from University of Southern California in 2007. He is a licensed Professional Engineer (P.E.) in the State of Texas and a SPE Certified Petroleum Engineer (S.P.E.C.). He is also a member of the Society of Petroleum Engineers (SPE) and the Society of Petroleum Evaluation Engineers (SPEE).

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Famurewa fulfills. As part of his 2020 continuing education hours, Mr. Famurewa attended and internally received over 15 hours of formalized training, some of which related to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Famurewa is a regular speaker on reserve related topics at the annual Sub-Saharan Africa Oil and Gas Conference in Houston, Texas USA.

Based on his educational background, professional training and more than 20 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Famurewa has attained the professional qualifications as a Reserves Estimator and Reserves Auditor as set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

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

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

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

<u>DEVELOPED RESERVES (SEC DEFINITIONS)</u>

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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

> *(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and*
>
> *(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.*

<u>Developed Producing (SPE-PRMS Definitions)</u>

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

<u>Developed Producing Reserves</u>

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.