UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2019

☐ **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®

Kosmos Energy Ltd.
(Exact name of registrant as specified in its charter)

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

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

Registrant's telephone number, including area code: **+1 214 445 9600**

Not applicable
(Former name, former address and former fiscal year, if changed since last report)

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 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 is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at August 1, 2019
Common Shares, $0.01 par value	401,458,556

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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 wholly owned subsidiaries. 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.
"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.
"Bwpd"	Barrels of water per day.
"Debt cover ratio"	The "debt cover ratio" is broadly defined, for each applicable calculation date, as the ratio of (x) total long-term debt less cash and cash equivalents and restricted cash, to (y) the aggregate EBITDAX (see below) of the Company for the previous twelve months.

“Developed acreage”	The number of acres that are allocated or assignable to productive wells or wells capable of production.
“Development”	The phase in which an oil or natural gas field is brought into production by drilling development wells and installing appropriate production systems.
"DGE"	Deep Gulf Energy (together with its subsidiaries).
“Dry hole" or "Unsuccessful well”	A well that has not encountered a hydrocarbon bearing reservoir expected to produce in commercial quantities.
“EBITDAX”	Net income (loss) plus (i) exploration expense, (ii) depletion, depreciation and amortization expense, (iii) equity-based compensation expense, (iv) unrealized (gain) loss on commodity derivatives (realized losses are deducted and realized gains are added back), (v) (gain) loss on sale of oil and gas properties, (vi) interest (income) expense, (vii) income taxes, (viii) loss on extinguishment of debt, (ix) doubtful accounts expense and (x) similar other material items which management believes affect the comparability of operating results. The Facility EBITDAX definition includes 50% of the EBITDAX adjustments of Kosmos-Trident International Petroleum Inc 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.
"ESP"	Electric submersible pump.
“E&P”	Exploration and production.
“FASB”	Financial Accounting Standards Board.
“Farm-in”	An agreement whereby a party acquires a portion of the participating interest in a block from the owner of such interest, usually in return for cash and/or for taking on a portion of future costs or other performance by the assignee as a condition of the assignment.
“Farm-out”	An agreement whereby the owner of the participating interest agrees to assign a portion of its participating interest in a block to another party for cash and/or for the assignee taking on a portion of future costs and/or other work as a condition of the assignment.
"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.
"GEPetrol"	Guinea Equatorial De Petroleos.

"GNPC"	Ghana National Petroleum Corporation.
"KBSL"	Kosmos BP Senegal Limited.
"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.
"Loan life cover ratio"	The "loan life cover ratio" is broadly defined, for each applicable forecast period, as the ratio of (x) net present value of forecasted net cash flow through the final maturity date of the Facility plus the net present value of forecasted capital expenditures incurred in relation to the Ghana and Equatorial Guinea assets, to (y) the aggregate loan amounts outstanding under the Facility.
"LNG"	Liquefied natural gas.
"MBbl"	Thousand barrels of oil.
"MBoe"	Thousand barrels of oil equivalent.
"Mcf"	Thousand cubic feet of natural gas.
"Mcfpd"	Thousand cubic feet per day of natural gas.
"MMBbl"	Million barrels of oil.
"MMBoe"	Million barrels of oil equivalent.
"MMBtu"	Million British thermal units.
"MMcf"	Million cubic feet of natural gas.
"MMcfd"	Million cubic feet per day of natural gas.
"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.
"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 planned 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.
"SNPC"	Société Nationale des Pétroles du Congo.
“Shelf margin”	The path created by the change in direction of the shoreline in reaction to the filling of a sedimentary basin.
"Shell"	Shell Exploration Company B.V.
“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 natural gas in the strata.
“Structural-stratigraphic trap”	A structural-stratigraphic trap is a combination trap with structural and stratigraphic features.

“Submarine fan”	A fan-shaped deposit of sediments occurring in a deep water setting where sediments have been transported via mass flow, gravity induced, processes from the shallow to deep water. These systems commonly develop at the bottom of sedimentary basins or at the end of large rivers.
“Three-way fault trap”	A structural trap where at least one of the components of closure is formed by offset of rock layers across a fault.
“Trap”	A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate.
"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.

KOSMOS ENERGY LTD.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	June 30, 2019	December 31, 2018
	(Unaudited)	
Assets		
Current assets:		
Cash and cash equivalents	$ 176,908	$ 173,515
Restricted cash	327	4,527
Receivables:		
Joint interest billings, net	55,360	64,572
Oil sales	83,685	48,164
Related party	—	5,580
Other	21,899	21,690
Inventories	108,528	84,827
Prepaid expenses and other	41,496	68,040
Derivatives	11,511	38,785
Total current assets	499,714	509,700
Property and equipment:		
Oil and gas properties, net	3,832,525	3,444,864
Other property, net	15,048	14,837
Property and equipment, net	3,847,573	3,459,701
Other assets:		
Equity method investment	—	51,896
Restricted cash	7,574	7,574
Long-term receivables	28,140	19,002
Deferred financing costs, net of accumulated amortization of $13,373 and $12,065 at June 30, 2019 and December 31, 2018, respectively	7,629	8,937
Deferred tax assets	43,710	14,004
Derivatives	7,264	14,312
Other	24,130	3,063
Total assets	$ 4,465,734	$ 4,088,189
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable	$ 157,373	$ 176,540
Accrued liabilities	258,379	195,596
Derivatives	26,897	12,172
Total current liabilities	442,649	384,308
Long-term liabilities:		
Long-term debt, net	2,129,340	2,120,547
Derivatives	5,776	10,181
Asset retirement obligations	276,692	145,336
Deferred tax liabilities	697,792	477,179
Other long-term liabilities	29,274	9,160
Total long-term liabilities	3,138,874	2,762,403
Stockholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at June 30, 2019 and December 31, 2018	—	—
Common stock, $0.01 par value; 2,000,000,000 authorized shares; 445,638,161 and 442,914,675 issued at June 30, 2019 and December 31, 2018, respectively	4,456	4,429
Additional paid-in capital	2,320,024	2,341,249
Accumulated deficit	(1,203,262)	(1,167,193)
Treasury stock, at cost, 44,263,269 and 44,263,269 shares at June 30, 2019 and December 31, 2018, respectively	(237,007)	(237,007)
Total stockholders' equity	884,211	941,478
Total liabilities and stockholders' equity	$ 4,465,734	$ 4,088,189

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Revenues and other income:				
Oil and gas revenue	$ 395,933	$ 215,191	$ 692,723	$ 342,387
Other income, net	1	282	1	263
Total revenues and other income	395,934	215,473	692,724	342,650
Costs and expenses:				
Oil and gas production	90,977	49,815	170,776	96,583
Facilities insurance modifications, net	2,278	1,029	(17,743)	9,478
Exploration expenses	29,905	77,481	60,249	98,674
General and administrative	28,072	17,497	63,980	39,380
Depletion, depreciation and amortization	151,438	74,289	269,533	128,566
Interest and other financing costs, net	59,803	18,870	94,844	44,564
Derivatives, net	(14,185)	140,272	62,900	178,750
Gain on equity method investments, net	—	(16,100)	—	(34,796)
Other expenses, net	(1,793)	938	326	4,643
Total costs and expenses	346,495	364,091	704,865	565,842
Income (loss) before income taxes	49,439	(148,618)	(12,141)	(223,192)
Income tax expense (benefit)	32,602	(45,345)	23,928	(69,693)
Net income (loss)	$ 16,837	$ (103,273)	$ (36,069)	$ (153,499)
Net income (loss) per share:				
Basic	$ 0.04	$ (0.26)	$ (0.09)	$ (0.39)
Diluted	$ 0.04	$ (0.26)	$ (0.09)	$ (0.39)
Weighted average number of shares used to compute net income (loss) per share:				
Basic	401,323	396,826	401,244	396,218
Diluted	408,230	396,826	401,244	396,218
Dividends declared per common share	$ 0.0452	$ —	$ 0.0904	$ —

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In thousands)

(Unaudited)

	Common Shares		Additional Paid-in	Accumulated	Treasury	
	Shares	Amount	Capital	Deficit	Stock	Total
2019:						
Balance as of December 31, 2018	442,915	$ 4,429	$ 2,341,249	$ (1,167,193)	$ (237,007)	$ 941,478
Dividends ($0.0452 per share)	—	—	(18,744)	—	—	(18,744)
Equity-based compensation	—	—	8,744	—	—	8,744
Restricted stock awards and units	2,610	26	(26)	—	—	—
Purchase of treasury stock / tax withholdings	—	—	(1,979)	—	—	(1,979)
Net loss	—	—	—	(52,906)	—	(52,906)
Balance as of March 31, 2019	445,525	4,455	2,329,244	(1,220,099)	(237,007)	876,593
Dividends ($0.0452 per share)	—	—	(18,740)	—	—	(18,740)
Equity-based compensation	—	—	9,525	—	—	9,525
Restricted stock awards and units	113	1	(1)	—	—	—
Purchase of treasury stock / tax withholdings	—	—	(4)	—	—	(4)
Net income	—	—	—	16,837	—	16,837
Balance as of June 30, 2019	445,638	$ 4,456	$ 2,320,024	$ (1,203,262)	$ (237,007)	$ 884,211
2018:						
Balance as of December 31, 2017	398,599	$ 3,986	$ 2,014,525	$ (1,073,202)	$ (48,197)	$ 897,112
Equity-based compensation	—	—	8,392	—	—	8,392
Restricted stock awards and units	6,380	64	(64)	—	—	—
Purchase of treasury stock / tax withholdings	—	—	(11,364)	—	(510)	(11,874)
Net loss	—	—	—	(50,226)	—	(50,226)
Balance as of March 31, 2018	404,979	4,050	2,011,489	(1,123,428)	(48,707)	843,404
Equity-based compensation	—	—	9,821	—	—	9,821
Restricted stock awards and units	2,578	26	(26)	—	—	—
Purchase of treasury stock / tax withholdings	—	—	(5,821)	—	—	(5,821)
Net loss	—	—	—	(103,273)	—	(103,273)
Balance as of June 30, 2018	407,557	$ 4,076	$ 2,015,463	$ (1,226,701)	$ (48,707)	$ 744,131

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(Unaudited)

	Six Months Ended June 30,	
	2019	**2018**
Operating activities		
Net loss	$ (36,069)	$ (153,499)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation and amortization	274,222	133,289
Deferred income taxes	(56,730)	(81,876)
Unsuccessful well costs and leasehold impairments	7,099	44,654
Change in fair value of derivatives	65,686	177,790
Cash settlements on derivatives, net (including $(18.7) million and $(57.3) million on commodity hedges during 2019 and 2018)	(21,044)	(56,221)
Equity-based compensation	17,932	17,085
Loss on extinguishment of debt	24,794	4,056
Distributions in excess of equity in earnings	—	5,234
Other	7,417	449
Changes in assets and liabilities:		
(Increase) decrease in receivables	(23,996)	10,067
(Increase) decrease in inventories	(19,021)	800
Decrease in prepaid expenses and other	29,380	4,888
Decrease in accounts payable	(76,031)	(13,316)
Increase (decrease) in accrued liabilities	28,751	(92,967)
Net cash provided by operating activities	222,390	433
Investing activities		
Oil and gas assets	(153,268)	(92,650)
Other property	(5,230)	(2,815)
Return of investment from KTIPI	—	79,970
Notes receivable from partners	(5,983)	—
Net cash used in investing activities	(164,481)	(15,495)
Financing activities		
Borrowings under long-term debt	175,000	—
Payments on long-term debt	(300,000)	(100,000)
Net proceeds from issuance of senior notes	641,875	—
Redemption of senior secured notes	(535,338)	—
Purchase of treasury stock / tax withholdings	(1,983)	(17,695)
Dividends	(36,289)	—
Deferred financing costs	(1,981)	(25,743)
Net cash used in financing activities	(58,716)	(143,438)
Net decrease in cash, cash equivalents and restricted cash	(807)	(158,500)
Cash, cash equivalents and restricted cash at beginning of period	185,616	304,986
Cash, cash equivalents and restricted cash at end of period	$ 184,809	$ 146,486
Supplemental cash flow information		
Cash paid for:		
Interest, net of capitalized interest	$ 65,307	$ 47,845
Income taxes	$ 14,619	$ 22,596

See accompanying notes.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements
(Unaudited)

1. Organization

Kosmos Energy Ltd. changed its jurisdiction of incorporation from Bermuda to the State of Delaware (the "Redomestication") in December 2018. As a holding company, Kosmos Energy Ltd.'s management operations are conducted through a wholly-owned subsidiary, Kosmos Energy, LLC. The terms "Kosmos," the "Company," "we," "us," "our," "ours," and similar terms refer to Kosmos Energy Ltd. and its wholly-owned subsidiaries, unless the context indicates otherwise.

Kosmos is a full-cycle deepwater independent oil and gas exploration and production company focused along the Atlantic Margins. Our key assets include production offshore Ghana, Equatorial Guinea and U.S. Gulf of Mexico, as well as a world-class gas development offshore Mauritania and Senegal. We also maintain a sustainable exploration program balanced between proven basin infrastructure-led exploration (Equatorial Guinea and U.S. Gulf of Mexico), emerging basins (Mauritania, Senegal and Suriname) and frontier basins (Cote d'Ivoire, Namibia and Sao Tome and Principe). Kosmos is listed on the New York Stock Exchange and London Stock Exchange 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 U.S. Gulf of Mexico. In addition, we have exploration activities in other countries in the Atlantic Margins.

2. Accounting Policies

General

The interim consolidated financial statements included in this report are unaudited and, in the opinion of management, include all adjustments of a normal recurring nature necessary for a fair presentation of the results for the interim periods. The results of the interim periods shown in this report are not necessarily indicative of the final results to be expected for the full year. The consolidated financial statements were prepared in accordance with the requirements of the Securities and Exchange Commission ("SEC") for interim reporting. As permitted under those rules, certain notes or other financial information that are normally required by Generally Accepted Accounting Principles in the United States of America ("GAAP") have been condensed or omitted from these interim consolidated financial statements. These consolidated financial statements and the accompanying notes should be read in conjunction with our audited consolidated financial statements for the year ended December 31, 2018, included in our annual report on Form 10-K.

Reclassifications

Certain prior period amounts have been reclassified to conform with the current presentation. Such reclassifications had no significant impact on our reported net income (loss), current assets, total assets, current liabilities, total liabilities, stockholders' equity or cash flows. Additionally, as a result of our outstanding shares in KTIPI being transferred for an undivided interest in the Ceiba Field and Okume Complex (effective January 1, 2019), our previously reported equity method investment in KTIPI has been allocated to the respective assets and liabilities on a relative fair value basis. See Note 7 — Equity Method Investments for additional information.

Cash, Cash Equivalents and Restricted Cash

	June 30, 2019	December 31, 2018
	(In thousands)	
Cash and cash equivalents	$ 176,908	$ 173,515
Restricted cash - current	327	4,527
Restricted cash - long-term	7,574	7,574
Total cash, cash equivalents and restricted cash shown in the consolidated statements of cash flows	$ 184,809	$ 185,616

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

In accordance with certain of our petroleum contracts, we have posted letters of credit related to performance guarantees for our minimum work obligations. These letters of credit are cash collateralized in accounts held by us and as such are classified as restricted cash. Upon completion of the minimum work obligations and/or entering into the next phase of the respective 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.

Inventories

Inventories consisted of $98.2 million and $83.4 million of materials and supplies and $10.3 million and $1.4 million of hydrocarbons as of June 30, 2019 and December 31, 2018, 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.

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 (Policy applicable beginning January 1, 2019)

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. Further, we do not expect the amendments in ASU 2018-01: Land Easement Practical Expedient to have an effect on us because we do not enter into land easement arrangements.

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 June 30, 2019 and December 31, 2018, 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:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(In thousands)			
Revenues from contract with customer - Equatorial Guinea	$ 63,165	$ —	$ 152,279	$ —
Revenues from contract with customer - Ghana	209,469	213,841	328,800	341,878
Revenues from contract with customers - U.S. Gulf of Mexico	129,364	—	214,431	—
Provisional oil sales contracts	(6,065)	1,350	(2,787)	509
Oil and gas revenue	$ 395,933	$ 215,191	$ 692,723	$ 342,387

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 three and six months ended June 30, 2019, revenue from Phillips 66 Company made up approximately 22% of our total consolidated revenue and was included in our U.S. Gulf of Mexico segment.

Recent Accounting Standards

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 is effective January 1, 2020, and we are evaluating the impact of this standard.

3. Acquisitions and Divestitures

2019 Transactions

During the first quarter of 2019, we entered into a petroleum contract covering offshore Marine XXI block with the Republic of the Congo, subject to customary governmental approvals. Upon approval, we will hold an 85% participating interest and are the operator. The Congolese national oil company, SNPC, has a 15% carried participating interest during the exploration period. Should a commercial discovery be made, SNPC's 15% carried interest will convert to a participating interest of at least 15%. The petroleum contract covers approximately 2,350 square kilometers, with a first exploration period of four years and includes a work program to acquire and interpret 2,200 square kilometers of 3D seismic. There are two optional exploration phases, each for a period of three years, which are subject to additional work program commitments.

During the first quarter of 2019, Kosmos farmed-in to 18 BP-owned blocks in the Garden Banks area of the deepwater U.S. Gulf of Mexico. In addition, Kosmos can earn an interest in three BP blocks in other areas of the deepwater U.S. Gulf of Mexico. Kosmos is the designated operator and plans to commence drilling operations on the first well in Garden Banks block 492, the Resolution prospect, in late 2019.

During the first quarter of 2019, Kosmos executed a farm-in agreement with Chevron covering the right to earn an interest in a deepwater block in the U.S. Gulf of Mexico. Kosmos has been designated operator and plans to commence drilling operations in 2019.

During the first quarter of 2019, Kosmos was one of the most active participants in the U.S. Gulf of Mexico Federal Lease Sale 252 and was ultimately awarded nine deepwater blocks.

During the first quarter of 2019, we executed 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, subject to customary governmental approvals. 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 May of 2019, we entered into 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, subject to customary governmental approvals.

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 and BP. We have a 35% participating interest in the blocks and the operator, BP, holds a 50% participating interest. The national petroleum agency, 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 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 a 40% non-operated participating interest. 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 future 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. In March 2019, we acquired Ophir's remaining interest in the block, which resulted in Kosmos owning an 80% participating interest in Block EG-24 and we are the operator. The Equatorial Guinean national oil company, GEPetrol, has a 20% carried participating interest during the exploration period. Should a commercial discovery be made, GEPetrol's 20% carried participating interest will convert to a 20% participating interest.

In August 2018, we closed a farm-out agreement with Trident, whereby they acquired a 40% participating interest in blocks EG-21, S, and W, offshore Equatorial Guinea, resulting in a $7.7 million gain. After giving effect to the farm-out agreement, we hold a 40% participating interest and are the operator in all three blocks. The Equatorial Guinean national oil company, GEPetrol, has a 20% carried participating interest during the exploration period. Should a commercial discovery be made, GEPetrol's 20% carried participating interest will convert to a 20% participating interest. The petroleum contracts cover approximately 6,000 square kilometers, with a first exploration period of five years from the effective date (March 2018). The first exploration period consists of two sub-periods of three and two years, respectively. The first exploration sub-period work program includes a 6,000 square kilometer 3D seismic acquisition requirement across the three blocks, which was completed in 2018.

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. The DGE acquisition was accounted as an asset acquisition.

In October 2018, Kosmos entered into a strategic exploration alliance with Shell to jointly explore in Southern West Africa. Initially the alliance will focus on Namibia where Kosmos has completed a farm-in to Shell's acreage in PEL 39, and Sao Tome and Principe where, in May 2019, we have entered into a farm-out agreement for Shell to take an interest in a portion of Kosmos' acreage in Blocks 6 and 11. As part of the alliance, the two companies intend to jointly evaluate opportunities in adjacent geographies. This alliance is consistent with Kosmos' strategy of partnering with supermajors to leverage complementary skill sets. Shell has deep expertise in carbonate plays, while Kosmos brings significant knowledge of the Cretaceous in West Africa. Furthermore, by working with Shell, Kosmos has a partner with the expertise to efficiently move exploration successes through the development stage.

4. Joint Interest Billings, Related Party Receivables and Notes Receivables

Joint Interest Billings

The Company's joint interest billings generally 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 2014, GNPC notified us and our block partners of its request for the contractor group to pay GNPC's 5% share of the Tweneboa, Enyenra and Ntomme ("TEN") development costs. The block partners are being reimbursed for such costs plus interest out of a portion of GNPC's TEN production revenues. As of June 30, 2019 and December 31, 2018, the current portions of the joint interest billing receivables due from GNPC for the TEN fields development costs were $14.0 million and $14.0 million, respectively, and the long-term portions were $22.2 million and $14.0 million, respectively.

Related Party Receivables

The Company's related party receivables consists primarily of receivables from Trident which, until January 2019, we shared a 50% interest in KTIPI. As of December 31, 2018 the balance due from Trident consists of $5.6 million related to joint interest billings for the exploration blocks and Kosmos' support of KTIPI operations. Subsequent to the unwind of KTIPI, Trident is no longer considered a related party.

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 for Greater Tortue Ahmeyim Phase 1, currently projected in the first half of 2022. Kosmos' total 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 June 30, 2019, the balance due from the national oil companies was $6.0 million, 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:

	June 30, 2019	December 31, 2018
	(In thousands)	
Oil and gas properties:		
Proved properties	$ 4,773,104	$ 4,236,489
Unproved properties	865,529	759,472
Total oil and gas properties	5,638,633	4,995,961
Accumulated depletion	(1,806,108)	(1,551,097)
Oil and gas properties, net	3,832,525	3,444,864
Other property	55,107	51,987
Accumulated depreciation	(40,059)	(37,150)
Other property, net	15,048	14,837
Property and equipment, net	$ 3,847,573	$ 3,459,701

We recorded depletion expense of $144.0 million and $71.3 million for the three months ended June 30, 2019 and 2018, respectively, and $255.0 million and $122.9 million for the six months ended June 30, 2019 and 2018, respectively. The increase to oil and gas properties from 2018 to 2019 primarily relates to proportionate consolidation resulting from the unwind of our equity method investment in KTIPI. See Note 7 — Equity Method Investments for additional information.

6. Suspended Well Costs

The following table reflects the Company's capitalized exploratory well costs on drilled wells as of and during the six months ended June 30, 2019. The table excludes $1.4 million in costs that were capitalized and subsequently expensed during the same period.

	June 30, 2019
	(In thousands)
Beginning balance	$ 367,665
Additions to capitalized exploratory well costs pending the determination of proved reserves	15,439
Reclassification due to determination of proved reserves	(10,711)
Capitalized exploratory well costs charged to expense	—
Ending balance	$ 372,393

The following table provides an 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:

	June 30, 2019	December 31, 2018
	(In thousands, except well counts)	
Exploratory well costs capitalized for a period of one year or less	$ —	$ —
Exploratory well costs capitalized for a period of one to two years	70,486	299,253
Exploratory well costs capitalized for a period of three years or greater	301,907	68,412
Ending balance	$ 372,393	$ 367,665
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	3	3

As of June 30, 2019, the projects with exploratory well costs capitalized for more than one year since the completion of drilling are related to the Greater Tortue Ahmeyim Unit, which crosses the Mauritania and Senegal maritime border, the Bir Allah 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.

Greater Tortue Ahmeyim Unit — In May 2015, we completed the Tortue-1 exploration well in Block C8 offshore Mauritania, which encountered hydrocarbon pay. Three additional wells have been drilled in the Greater Tortue Discovery area, Ahmeyim-2 in Mauritania and Guembeul-1 and Greater Tortue Ahmeyim-1 in Senegal. We completed a drill stem test on the Tortue-1 well in August 2017, which confirmed the production capabilities of the Greater Tortue Ahmeyim Unit. In December 2018, we made a final investment decision to develop Phase 1 of the Greater Tortue Ahmeyim Unit.

Bir Allah Discovery — In November 2015, we completed the Marsouin-1 exploration well (renamed Bir Allah) in the northern part of Block C8 offshore Mauritania, which encountered hydrocarbon pay. Following additional evaluation, a decision regarding commerciality is expected to be made. An exploration well is planned for the nearby Orca prospect during 2019, which will help delineate the available resource in the region to refine the development plans for the Bir Allah discovery.

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. The Yakaar-2 appraisal well is scheduled for drilling in the third quarter of 2019 to further evaluate the discovery. Following additional evaluation, a decision regarding commerciality is expected to be made.

7. 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, 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 and the results of operations for 2019 are presented based on our direct 40.4% 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 stockholders' equity	
Total current liabilities	$ 226,311
Total long-term liabilities	536,178
Shareholders' equity:	
Total shareholders' equity	(340,891)
Total liabilities and shareholders' equity	$ 421,598

	Three Months Ended June 30, 2018	Six Months Ended June 30, 2018
	(In thousands)	
Revenues and other income:		
Oil and gas revenue	$ 138,395	$ 384,749
Other income	(170)	117
Total revenues and other income	138,225	384,866
Costs and expenses:		
Oil and gas production	23,332	75,033
Depletion, depreciation and amortization	21,881	75,951
Other expenses, net	(73)	(152)
Total costs and expenses	45,140	150,832
Income before income taxes	93,085	234,034
Income tax expense	33,620	83,251
Net income	$ 59,465	$ 150,783
Kosmos' share of net income	$ 29,733	$ 75,392
Basis difference amortization(1)	13,633	40,596
Equity in earnings - KTIPI	$ 16,100	$ 34,796

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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.

With an effective date of January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.375% 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. 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. These fair value estimates were used to allocate the carrying value of the equity method investment to our balance sheet on a relative fair value basis.

	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

8. Debt

	June 30, 2019		December 31, 2018	
	(In thousands)			
Outstanding debt principal balances:				
Facility	$	1,500,000	$	1,325,000
Corporate Revolver		25,000		325,000
Senior Notes		650,000		—
Senior Secured Notes		—		525,000
Total		2,175,000		2,175,000
Unamortized deferred financing costs and discounts(1)		(45,660)		(54,453)
Long-term debt, net	$	2,129,340	$	2,120,547

(1) Includes $35.9 million and $40.5 million of unamortized deferred financing costs related to the Facility as of June 30, 2019 and December 31, 2018, respectively; $9.7 million of unamortized deferred financing costs and discounts related to the Senior Notes as of June 30, 2019; and $14.0 million of unamortized deferred financing costs and discounts related to the Senior Secured Notes as of December 31, 2018, respectively.

Facility

In February 2018, the Company amended and restated the Facility with a total commitment of $1.5 billion from a number of financial institutions with additional commitments up to $0.5 billion being available if the existing financial institutions increase their commitments or if commitments from new financial institutions are added. The borrowing base calculation includes value related to the Jubilee, TEN, Ceiba and Okume fields. In March 2019, following the lender's annual redetermination, the available borrowing base under our Facility was limited to the Facility size of $1.7 billion. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities. As part of the debt refinancing in February 2018, the repayment of borrowings under the existing facility attributable to financial institutions that did not participate in the amended Facility was accounted for as an extinguishment of debt, and $4.1 million of existing unamortized debt issuance costs and deferred interest attributable to those participants was expensed in interest and other financing costs, net in the first quarter of 2018. As of June 30, 2019, we have $35.9 million of unamortized issuance costs related to the Facility, which will be amortized over the remaining term of the Facility. As of June 30, 2019, borrowings under the Facility totaled $1.5 billion and the undrawn availability under the Facility was $100.0 million. The commitments were reduced by $100 million to $1.6 billion following the Senior Notes issuance in April 2019.

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 June 30, 2019, we had no letters of credit issued under the Facility.

We were in compliance with the financial covenants contained in the Facility as of March 31, 2019 (the most recent assessment date). The Facility contains customary cross default provisions.

Corporate Revolver

In August 2018, we amended and restated the Corporate Revolver from a number of financial institutions, maintaining the borrowing capacity at $400.0 million, extending the maturity date from November 2018 to May 2022 and lowering the margin 100 basis points to 5%. This 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 June 30, 2019, borrowings under the Corporate Revolver totaled $25.0 million and the undrawn availability under the Corporate Revolver was $375.0 million. As of June 30, 2019, we have $7.6 million of net deferred financing costs related to the Corporate Revolver, which will be amortized over its remaining term. We were in compliance with the financial covenants contained in the Corporate Revolver as of March 31, 2019 (the most recent assessment date). The Corporate Revolver contains customary cross default provisions.

Revolving Letter of Credit Facility

Our revolving letter of credit facility agreement (“LC Facility”) expired in July 2019. In December 2018, the LC Facility size was voluntarily reduced to $20.0 million based on the expiration of several large outstanding letters of credit. As of June 30, 2019, there were six outstanding letters of credit totaling $9.4 million under the LC Facility, which will remain outstanding until the respective letters of credit expire. The LC Facility contains customary cross default provisions.

In June 2019, we issued a $17.0 million letter of credit under a new letter of credit arrangement, which does not currently require cash collateral.

7.875% Senior Secured Notes due 2021

During August 2014, the Company issued $300.0 million of 7.875% Senior Secured Notes due 2021 (the "Senior Secured Notes") and received net proceeds of approximately $292.5 million after deducting discounts, commissions and debt issue costs. The Company used the net proceeds to repay a portion of the outstanding indebtedness under the Facility and for general corporate purposes.

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

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 during the second quarter.

7.125% Senior Notes due 2026

In April 2019, the Company issued $650.0 million of 7.125% Senior Notes (the "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 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.

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At June 30, 2019, the estimated repayments of debt during the five fiscal year periods and thereafter are as follows:

	Payments Due by Year						
	Total	2019(2)	2020	2021	2022	2023	Thereafter
	(In thousands)						
Principal debt repayments(1)	$ 2,175,000	$ —	$ —	$ 274,800	$ 309,200	$ 271,600	$ 1,319,400

(1) Includes the scheduled principal maturities for the $650.0 million aggregate principal amount of Senior Notes issued in April 2019, borrowings under the Facility and borrowings under the Corporate Revolver. The scheduled maturities of debt related to the Facility are based on, as of June 30, 2019, 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) Represents payments for the period July 1, 2019 through December 31, 2019.

Interest and other financing costs, net

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(In thousands)			
Interest expense	$ 38,450	$ 24,912	$ 76,622	$ 49,804
Amortization—deferred financing costs	2,302	2,283	4,689	4,723
Loss on extinguishment of debt	24,794	—	24,794	4,056
Capitalized interest	(7,002)	(9,292)	(14,253)	(14,112)
Deferred interest	433	166	1,270	(1,090)
Interest income	(591)	(843)	(1,243)	(1,791)
Other, net	1,417	1,644	2,965	2,974
Interest and other financing costs, net	$ 59,803	$ 18,870	$ 94,844	$ 44,564

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 June 30, 2019. Volumes and weighted average prices are net of any offsetting derivative contracts entered into.

				Weighted Average Price per Bbl				
Term	Type of Contract	Index	MBbl	Net Deferred Premium Payable/(Receivable)	Swap	Sold Put	Floor	Ceiling
2019:								
Jul — Dec	Three-way collars	Dated Brent	5,256	$ 1.17	$ —	$ 43.81	$ 53.33	$ 73.57
Jul — Dec	Sold calls(1)	Dated Brent	460	—	—	—	—	80.00
Jul — Dec	Swaps	NYMEX WTI	730	—	52.01	—	—	—
Jul — Dec	Collars	Argus LLS	500	—	—	—	60.00	88.75
2020:								
Jan — Dec	Three-way collars	Dated Brent	6,000	$ 0.45	$ —	$ 45.00	$ 57.50	$ 80.18
Jan — Dec	Sold calls(1)(2)	Dated Brent	8,000	$ 1.17	$ —	$ —	$ —	$ 85.00

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

(2) Deferred premium payable to be paid July 1, 2019 — December 31, 2019.

In July 2019, we entered into put option contracts for 2.0 MMBbl from January 2020 through December 2020 with a floor price of $60.00 per barrel and a sold put price of $50.00 per barrel. In addition, we sold 1.0 MMBbl of calls from January 2021 through December 2021 with a strike price of $75.00 per barrel. The contracts are indexed to Dated Brent prices.

The following tables disclose the Company's derivative instruments as of June 30, 2019 and December 31, 2018, and gain/(loss) from derivatives during the three and six months ended June 30, 2019 and 2018, respectively:

		Estimated Fair Value Asset (Liability)	
Type of Contract	Balance Sheet Location	June 30, 2019	December 31, 2018
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative assets:			
Commodity(1)	Derivatives assets—current	$ 11,511	$ 38,785
Commodity(2)	Derivatives assets—long-term	7,264	14,312
Derivative liabilities:			
Commodity(3)	Derivatives liabilities—current	(26,897)	(12,172)
Commodity(4)	Derivatives liabilities—long-term	(5,776)	(10,181)
Total derivatives not designated as hedging instruments		$ (13,898)	$ 30,744

(1) Includes zero and $0.4 million as of June 30, 2019 and December 31, 2018, respectively which represents our provisional oil sales contract. Also, includes net deferred premiums payable of $4.0 million and $1.6 million related to commodity derivative contracts as of June 30, 2019 and December 31, 2018, respectively.

(2) Includes net deferred premiums payable of $0.8 million and $1.3 million related to commodity derivative contracts as of June 30, 2019 and December 31, 2018, respectively.

(3) Includes net deferred premiums payable of $7.8 million and $18.0 million related to commodity derivative contracts as of June 30, 2019 and December 31, 2018, respectively.

(4) Includes net deferred premiums payable of $0.8 million and $0.5 million related to commodity derivative contracts as of June 30, 2019 and December 31, 2018, respectively.

		Amount of Gain/(Loss) Three Months Ended June 30,		Amount of Gain/(Loss) Six Months Ended June 30,	
Type of Contract	Location of Gain/(Loss)	2019	2018	2019	2018
		(In thousands)			
Derivatives not designated as hedging instruments:					
Commodity(1)	Oil and gas revenue	$ (6,064)	$ 1,350	$ (2,786)	$ 509
Commodity	Derivatives, net	14,185	(140,272)	(62,900)	(178,750)
Interest rate	Interest expense	—	98	—	451
Total derivatives not designated as hedging instruments		$ 8,121	$ (138,824)	$ (65,686)	$ (177,790)

(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 June 30, 2019 and December 31, 2018, 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 Topic 820 — Fair Value Measurements and Disclosures, fair value measurements are based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. We prioritize the inputs used in measuring fair value into the following fair value hierarchy:

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

The following tables present the Company's assets and liabilities that are measured at fair value on a recurring basis as of June 30, 2019 and December 31, 2018, 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)			
June 30, 2019				
Assets:				
Commodity derivatives	$ —	$ 18,775	$ —	$ 18,775
Liabilities:				
Commodity derivatives	—	(32,673)	—	(32,673)
Total	$ —	$ (13,898)	$ —	$ (13,898)
December 31, 2018				
Assets:				
Commodity derivatives	$ —	$ 53,097	$ —	$ 53,097
Liabilities:				
Commodity derivatives	—	(22,353)	—	(22,353)
Total	$ —	$ 30,744	$ —	$ 30,744

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 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 provisional oil sales derivatives 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 June 30, 2019 and December 31, 2018:

	June 30, 2019		December 31, 2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Senior Notes	$ 642,089	$ 656,422	$ —	$ —
Senior Secured Notes	—	—	511,873	525,026
Corporate Revolver	25,000	25,000	325,000	325,000
Facility	1,500,000	1,500,000	1,325,000	1,325,000
Total	$ 2,167,089	$ 2,181,422	$ 2,161,873	$ 2,175,026

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

11. Equity-based Compensation

Restricted Stock Units

We record equity-based compensation expense equal to the fair value of share-based payments over the vesting periods of the Long Term Incentive Plan ("LTIP") awards. We recorded compensation expense from awards granted under our LTIP of $9.5 million and $9.1 million during the three months ended June 30, 2019 and 2018, respectively, and $17.9 million and $17.1 million during the six months ended June 30, 2019 and 2018, respectively. The total tax benefit for the three months ended was $1.5 million and $1.8 million, respectively, and $2.8 million and $3.4 million during the six months ended June 30, 2019 and 2018, respectively. Additionally, we recorded a net tax shortfall (windfall) related to equity-based compensation of nil and $0.4 million for the three months ended June 30, 2019 and 2018, respectively, and $1.2 million and $(0.3) million during the six months ended June 30, 2019 and 2018, respectively. The fair value of awards vested during the three months ended June 30, 2019 and 2018 was approximately $0.8 million and $25.4 million, respectively, and $14.0 million and $82.0 million during the six months ended June 30, 2019 and 2018, respectively. The Company granted restricted stock units with service vesting criteria and a combination of market and service vesting criteria under the LTIP. Substantially all these grants vest over three years. Upon vesting, restricted stock units become issued and outstanding stock.

The following table reflects the outstanding restricted stock units as of June 30, 2019:

	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, 2018	4,115	$ 6.42	6,716	$ 9.02
Granted(1)	2,965	4.91	3,109	6.02
Forfeited(1)	(85)	6.33	(285)	9.92
Vested	(1,909)	5.87	(1,271)	6.36
Outstanding at June 30, 2019	5,086	5.74	8,269	8.39

(1) The restricted stock units with a combination of market and service vesting criteria may vest between 0% and 200% of the originally granted units depending upon market performance conditions. Awards vesting over or under target shares of 100% results in additional shares granted or forfeited, respectively, in the period the market vesting criteria is determined.

As of June 30, 2019, total equity-based compensation to be recognized on unvested restricted stock units is $47.0 million over a weighted average period of 2.14 years. In March 2018, the board of directors approved an amendment to the LTIP to add 11.0 million shares to the plan, which was approved by our stockholders at the Annual General Meeting in June 2018. The LTIP provides for the issuance of 50.5 million shares pursuant to awards under the plan. At June 30, 2019, the Company had approximately 9.9 million shares that remain available for issuance under the LTIP.

For restricted stock units with a combination of market and service vesting criteria, the number of common shares to be issued is determined by comparing the Company's total shareholder return with the total shareholder return of a predetermined group of peer companies over the performance period and can vest in up to 200% of the awards granted. The grant date fair value ranged from $4.83 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 and ranged from 0.8% to 2.5%.

12. 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. We evaluate our estimated annual effective income tax rate each quarter, based on current and forecasted business results and enacted tax laws, and apply this tax rate to our ordinary income or loss to calculate our estimated tax expense or benefit. The Company excludes zero tax rate and tax-exempt jurisdictions from our evaluation of the estimated annual effective income tax rate. The tax effect of discrete items are recognized in the period in which they occur at the applicable statutory tax rate. The company was not subject to taxation at the parent company level for the three and six months ended June 30, 2018.

For 2019, the income tax provision consists of United States, Ghanaian, and Equatorial Guinean income taxes, and Texas margin taxes. For 2018, results from operations in Equatorial Guinea are reported, net of tax, as Gain on equity method investments, net in our Consolidated Statement of Operations, and were not included in our 2018 income tax provision. 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.

Income (loss) before income taxes is composed of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(In thousands)			
United States	$ (18,499)	$ 1,682	$ (74,240)	$ 3,315
Bermuda	—	(15,890)	—	(31,961)
Foreign—other	67,938	(134,410)	62,099	(194,546)
Income (loss) before income taxes	$ 49,439	$ (148,618)	$ (12,141)	$ (223,192)

For the three months ended, June 30, 2019, and 2018, our effective tax rate was 66% and 31%, respectively. For the six months ended, June 30, 2019, and 2018, our effective tax rate was 197% and 31%, respectively.

For the three and six months ended June 30, 2019 our overall effective tax rate was impacted by the difference in our 21% U.S. income tax reporting rate and the 35% statutory tax rates applicable to our Ghanaian and Equatorial Guinean operations, non-deductible and non-taxable items associated with our U.S., Ghanaian, and Equatorial Guinean operations, and other losses and expenses, primarily related to 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 expenses or losses.

For the three and six months ended June 30, 2018, our overall effective tax rate was impacted by non-deductible and non-taxable items associated with our U.S. and Ghanaian operations and other losses and expenses, primarily related to 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 expenses or losses.

The Company files income tax returns in all jurisdictions where such requirements exist, however, our primary tax jurisdictions are the United States, Ghana and Equatorial Guinea. The Company is open to tax examinations in United States, for federal income tax return years 2015 through 2018, in Ghana to federal income tax return examinations for tax years 2014 through 2018, and in Equatorial Guinea to federal income tax return examination for 2018.

As of June 30, 2019, 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.

13. Net Income (Loss) Per Share

The following table is a reconciliation between net income (loss) and the amounts used to compute basic and diluted net income (loss) per share and the weighted average shares outstanding used to compute basic and diluted net income (loss) per share:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(In thousands, except per share data)			
Numerator:				
Net income (loss) allocable to common stockholders	$ 16,837	$ (103,273)	$ (36,069)	$ (153,499)
Denominator:				
Weighted average number of shares outstanding:				
Basic	401,323	396,826	401,244	396,218
Restricted stock units(1)	6,907	—	—	—
Diluted	408,230	396,826	401,244	396,218
Net income (loss) per share:				
Basic	$ 0.04	$ (0.26)	$ (0.09)	$ (0.39)
Diluted	$ 0.04	$ (0.26)	$ (0.09)	$ (0.39)

(1) We excluded outstanding restricted stock awards and units of 1.1 million and 11.4 million for the three months ended June 30, 2019 and 2018, respectively, and 12.9 million and 11.9 million for the six months ended June 30, 2019 and 2018, respectively, from the computations of diluted net income (loss) per share because the effect would have been anti-dilutive.

14. 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.

We currently have a commitment to drill one exploration well in each of Sao Tome and Principe and Namibia and two exploration wells in each of Mauritania and Senegal. In Mauritania and Senegal, BP is obligated to fund our share of the cost of the exploration wells, subject to the remaining exploration and appraisal carry covering our Mauritania and Senegal blocks. In Sao Tome and Principe, we also have 3D seismic acquisition requirements of approximately 13,500 square kilometers. In South Africa, subject to customary governmental approvals, we have 2D seismic acquisition requirements of approximately 500 line kilometers.

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 three and six months ended June 30, 2019 are as follows:

	Three months ended June 30, 2019	Six Months Ended June 30, 2019
	(In thousands)	
Operating lease cost	$ 1,602	$ 3,009
Short-term lease cost	582	587
Total lease cost	$ 2,184	$ 3,596

Other information related to operating leases at June 30, 2019, is as follows:

(In thousands, except lease term and discount rate)	June 30, 2019
Balance sheet classifications	
Other assets (right-of-use assets)	$ 21,432
Accrued liabilities (current maturities of leases)	3,018
Other long-term liabilities (non-current maturities of leases)	20,653
Weighted average remaining lease term	9.1 years
Weighted average discount rate	9.9%

The table below presents supplemental cash flow information related to leases during the six months ended June 30, 2019:

	Six Months Ended June 30, 2019
	(In thousands)
Operating cash flows for operating leases	$ 1,750

Future minimum rental commitments under our leases at June 30, 2019, are as follows:

	Operating Leases(1)
	(In thousands)
2019(2)	$ 1,100
2020	4,699
2021	3,895
2022	3,918
2023	3,907
Thereafter	19,520
Total undiscounted lease payments	$ 37,039
Less: Imputed interest	(13,368)
Total lease liabilities	$ 23,671

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

(2) Represents payments for the period from July 1, 2019 through December 31, 2019.

Performance Obligations

As of June 30, 2019 and December 31, 2018, the Company had secured performance bonds totaling $201.4 million and $200.9 million, respectively, for our supplemental bonding requirements stipulated by the BOEM and $3.7 million and $3.7 million, respectively, to another operator 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 June 30, 2019 and December 31, 2018, we had zero and $0.6 million, respectively, of cash collateral against these secured performance bonds which is classified as Other long term assets in our consolidated balance sheets.

Dividends

On August 2, 2019, we declared our quarterly cash dividend of $0.0452 per common share for the third quarter payable on September 26, 2019 to stockholders of record as of September 5, 2019.

15. Additional Financial Information

Accrued Liabilities

Accrued liabilities consisted of the following:

	June 30, 2019	December 31, 2018
	(In thousands)	
Accrued liabilities:		
Exploration, development and production	$ 109,176	$ 92,613
Revenue payable	37,030	24,379
Current asset retirement obligations	6,967	6,617
Operating lease liabilities	3,018	—
General and administrative expenses	23,949	39,373
Interest	12,635	18,152
Income taxes	56,358	8,958
Taxes other than income	5,012	4,613
Derivatives	2,665	441
Other	1,569	450
	$ 258,379	$ 195,596

Asset Retirement Obligations

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

		June 30, 2019
		(In thousands)
Asset retirement obligations:		
Beginning asset retirement obligations	$	151,953
Additions associated with Equatorial Guinea - Ceiba Field and Okume Complex		114,395
Liabilities incurred during period		5,762
Liabilities settled during period		(1,228)
Revisions in estimated retirement obligations		1,164
Accretion expense		11,613
Ending asset retirement obligations	$	283,659

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

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. During the three months ended June 30, 2019 and 2018, we incurred approximately $11.2 million and $9.5 million, respectively in expenditures offset by approximately $8.9 million and $8.4 million, respectively in insurance recoveries. During the six months ended June 30, 2019 and 2018, we incurred approximately $22.2 million and $19.2 million, respectively in expenditures offset by approximately $39.9 million and $9.7 million, respectively in insurance recoveries.

Other Expenses, Net

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2019		2018		2019		2018	
	(In thousands)							
Income (loss) on disposal of inventory	$	—	$	(24)	$	187	$	(24)
Income (loss) on ARO liability settlements		(5)		—		1,913		—
Disputed charges and related costs, net of recoveries		—		626		(14)		2,961
Other, net		(1,788)		336		(1,760)		1,706
Other expenses, net	$	(1,793)	$	938	$	326	$	4,643

The disputed charges and related costs, net of recoveries arise from the final award issued by the International Chamber of Commerce ("ICC") in favor of Kosmos in its arbitration against Tullow Ghana Limited, related to expenditures arising from Tullow's contract with Seadrill for use of the West Leo drilling rig.

16. Business Segment Information

Kosmos is engaged in a single line of business, which is the exploration, development and production of oil and gas. At June 30, 2019, substantially all of our long-lived assets and all of our product sales are related to operations in four geographic reporting segments: Ghana, Equatorial Guinea, Mauritania/Senegal and the U.S. Gulf of Mexico. In addition, we have exploration activities in other countries in the Atlantic Margins. 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)			
Three months ended June 30, 2019							
Revenues and other income:							
Oil and gas revenue	$ 202,085	$ 64,484	$ —	$ 129,364	$ —	$ —	$ 395,933
Other income, net	1	—	—	124	19,079	(19,203)	1
Total revenues and other income	202,086	64,484	—	129,488	19,079	(19,203)	395,934
Costs and expenses:							
Oil and gas production	44,954	16,670	—	29,353	—	—	90,977
Facilities insurance modifications, net	2,278	—	—	—	—	—	2,278
Exploration expenses	56	2,472	2,043	11,015	14,319	—	29,905
General and administrative	6,002	1,539	1,540	4,893	44,313	(30,215)	28,072
Depletion, depreciation and amortization	75,898	16,287	15	58,215	1,023	—	151,438
Interest and other financing costs, net(1)	19,026	—	(6,524)	5,642	43,443	(1,784)	59,803
Derivatives, net	—	—	—	(1,390)	(12,795)	—	(14,185)
Other expenses, net	(12,982)	(2,583)	412	553	11	12,796	(1,793)
Total costs and expenses	135,232	34,385	(2,514)	108,281	90,314	(19,203)	346,495
Income (loss) before income taxes	66,854	30,099	2,514	21,207	(71,235)	—	49,439
Income tax expense (benefit)	24,683	11,762	—	4,439	(8,282)	—	32,602
Net income (loss)	$ 42,171	$ 18,337	$ 2,514	$ 16,768	$ (62,953)	$ —	$ 16,837
Consolidated capital expenditures	$ 33,496	$ 6,115	$ 4,039	$ 41,177	$ 15,858	$ —	$ 100,685

	Ghana	Equatorial Guinea	Mauritania/Senegal	U.S. Gulf of Mexico	Corporate & Other	Eliminations	Total
				(In thousands)			
Six months ended June 30, 2019							
Revenues and other income:							
Oil and gas revenue	$ 325,003	$ 153,289	$ —	$ 214,431	$ —	$ —	$ 692,723
Other income, net	1	—	—	259	91,888	(92,147)	1
Total revenues and other income	325,004	153,289	—	214,690	91,888	(92,147)	692,724
Costs and expenses:					—		
Oil and gas production	75,010	39,276	—	56,490	—	—	170,776
Facilities insurance modifications, net	(17,743)	—	—	—	—	—	(17,743)
Exploration expenses	107	5,643	8,485	22,209	23,805	—	60,249
General and administrative	11,958	3,584	3,827	12,286	88,519	(56,194)	63,980
Depletion, depreciation and amortization	130,761	39,304	31	97,409	2,028	—	269,533
Interest and other financing costs, net(1)	39,679	—	(13,317)	11,571	60,478	(3,567)	94,844
Derivatives, net	—	—	—	30,513	32,387	—	62,900
Other expenses, net	32,118	(2,243)	641	2,145	51	(32,386)	326
Total costs and expenses	271,890	85,564	(333)	232,623	207,268	(92,147)	704,865
Income (loss) before income taxes	53,114	67,725	333	(17,933)	(115,380)	—	(12,141)
Income tax expense (benefit)	19,700	27,293	—	(3,766)	(19,299)	—	23,928
Net income (loss)	$ 33,414	$ 40,432	$ 333	$ (14,167)	$ (96,081)	$ —	$ (36,069)
Consolidated capital expenditures	$ 68,463	$ 21,051	$ 6,290	$ 87,059	$ 28,050	$ —	$ 210,913
As of June 30, 2019							
Property and equipment, net	$ 1,643,410	$ 460,679	$ 422,539	$ 1,281,439	$ 39,506	$ —	$ 3,847,573
Total assets	$ 1,872,202	$ 498,195	$ 546,454	$ 3,343,917	$ 12,051,009	$ (13,846,043)	$ 4,465,734

(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)			
Three months ended June 30, 2018							
Revenues and other income:							
Oil and gas revenue	$ 215,192	$ 69,198	$ —	$ —	$ (1)	$ (69,198)	$ 215,191
Other income, net	1	197	—	—	172,546	(172,462)	282
Total revenues and other income	215,193	69,395	—	—	172,545	(241,660)	215,473
Costs and expenses:							
Oil and gas production	49,274	11,666	—	—	541	(11,666)	49,815
Facilities insurance modifications, net	1,029	—	—	—	—	—	1,029
Exploration expenses	34	16,211	2,202	—	59,034	—	77,481
General and administrative	4,612	1,022	941	—	41,376	(30,454)	17,497
Depletion, depreciation and amortization	73,110	24,574	15	—	1,164	(24,574)	74,289
Interest and other financing costs, net(4)	22,114	(4)	(8,341)	—	6,885	(1,784)	18,870
Derivatives, net	—	—	—	—	140,272	—	140,272
(Gain) loss on equity method investments, net	—	—	—	—	—	(16,100)	(16,100)
Other expenses, net	140,901	(283)	(1)	—	594	(140,273)	938
Total costs and expenses	291,074	53,186	(5,184)	—	249,866	(224,851)	364,091
Income (loss) before income taxes	(75,881)	16,209	5,184	—	(77,321)	(16,809)	(148,618)
Income tax expense (benefit)	(46,603)	16,810	—	—	1,258	(16,810)	(45,345)
Net income (loss)	$ (29,278)	$ (601)	$ 5,184	$ —	$ (78,579)	$ 1	$ (103,273)
Consolidated capital expenditures	$ 20,727	$ 18,086	$ 3,058	$ —	$ 55,302	$ —	$ 97,173

	Ghana	Equatorial Guinea(1)	Mauritania/Senegal	U.S. Gulf of Mexico(2)	Corporate & Other	Eliminations(3)	Total
	(In thousands)						
Six months ended June 30, 2018							
Revenues and other income:							
Oil and gas revenue	$ 342,387	$ 192,375	$ —	$ —	$ —	$ (192,375)	$ 342,387
Other income, net	(18)	340	—	—	237,606	(237,665)	263
Total revenues and other income	342,369	192,715	—	—	237,606	(430,040)	342,650
Costs and expenses:							
Oil and gas production	94,579	37,516	—	—	2,004	(37,516)	96,583
Facilities insurance modifications, net	9,478	—	—	—	—	—	9,478
Exploration expenses	258	17,080	5,400	—	75,936	—	98,674
General and administrative	9,865	2,007	2,232	—	80,486	(55,210)	39,380
Depletion, depreciation and amortization	126,461	78,572	31	—	2,074	(78,572)	128,566
Interest and other financing costs, net(4)	43,368	(5)	(12,263)	—	17,031	(3,567)	44,564
Derivatives, net	—	—	—	—	178,750	—	178,750
(Gain) loss on equity method investments, net	—	—	—	—	—	(34,796)	(34,796)
Other expenses, net	181,709	(162)	—	—	1,849	(178,753)	4,643
Total costs and expenses	465,718	135,008	(4,600)	—	358,130	(388,414)	565,842
Income (loss) before income taxes	(123,349)	57,707	4,600	—	(120,524)	(41,626)	(223,192)
Income tax expense (benefit)	(71,011)	41,626	—	—	1,318	(41,626)	(69,693)
Net income (loss)	$ (52,338)	$ 16,081	$ 4,600	$ —	$ (121,842)	$ —	$ (153,499)
Consolidated capital expenditures	$ 38,829	$ 24,978	$ 6,314	$ —	$ 84,681	$ —	$ 154,802
As of June 30, 2018							
Property and equipment, net	$ 1,818,613	$ 9,806	$ 394,569	$ —	$ 40,076	$ —	$ 2,263,064
Total assets	$ 2,110,848	$ 165,284	$ 461,536	$ —	$ 8,741,413	$ (8,575,638)	$ 2,903,443

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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 three and six months ended June 30, 2018, except for capital expenditures. See Note 7 - Equity Method Investments for additional information regarding our equity method investments.

(2) No activity prior to 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.

	Six Months Ended June 30,	
	2019	2018
	(In thousands)	
Consolidated capital expenditures:		
Consolidated Statements of Cash Flows - Investing activities:		
Oil and gas assets	$ 153,268	$ 92,650
Other property	5,230	2,815
Adjustments:		
Changes in capital accruals	13,684	19,317
Exploration expense, excluding unsuccessful well costs(1)	53,150	54,020
Capitalized interest	(14,253)	(14,112)
Other	(166)	112
Total consolidated capital expenditures	$ 210,913	$ 154,802

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

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes thereto contained herein and our annual financial statements for the year ended December 31, 2018, included in our annual report on Form 10-K along with the section Management's Discussion and Analysis of financial condition and Results of Operations contained in such annual report. Any terms used but not defined in the following discussion have the same meaning given to them in the annual report. Our discussion and analysis includes forward-looking statements that involve risks and uncertainties and should be read in conjunction with "Risk Factors" under Item 1A of this report and in the annual report, along with "Forward-Looking Information" at the end of this section for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

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

Recent Developments

Corporate

During April 2019, the Company issued $650 million of 7.125% Senior Notes due 2026 ("Senior Notes") and received net proceeds of approximately $640.0 million after deducting commission and deferred financing costs. We used the net proceeds to fund the redemption of our 7.875% Senior Secured Notes due 2021 ("Senior Secured Notes"), of which there was a $525 million aggregate principal amount outstanding, to repay a portion of the outstanding indebtedness under our Corporate Revolver and to pay fees and expenses related to the redemption, repayment and the offering.

Ghana

Jubilee

During the second quarter of 2019, Jubilee production averaged approximately 97,000 Bopd (gross). During the first quarter, gas reliability issues were worked on by the operator with the reliability of the gas system enhanced by having a spare high-pressure compressor available. However, oil production rates remain constrained by gas handling capabilities. The partnership is working to enhance gas handling capacity in the fourth quarter of 2019.

Tweneboa, Enyenra and Ntomme ("TEN")

During the second quarter of 2019, TEN production averaged approximately 59,100 Bopd (gross). The completion of the Enyenra-14 production well was suspended due to operational issues.

U.S. Gulf of Mexico

Production from the U.S. Gulf of Mexico averaged approximately 26,400 Boepd (net) for the second quarter of 2019.

During the second quarter of 2019, Kosmos was awarded all nine deepwater blocks which the Company was deemed the apparent high bidder from the U.S. Gulf of Mexico Federal Lease Sale 252. As part of the Company's strategy to expand its position in the U.S. Gulf of Mexico, these new leases have added significant infrastructure-led exploration prospects to our portfolio.

In the second quarter of 2019, we announced the Gladden Deep exploration well located in Mississippi Canyon Block 800 (20.0% working interest) made an oil discovery. Gladden Deep is a subsea tieback which is expected to be brought online through the existing Gladden pipeline to the Medusa SPAR in the fourth quarter of 2019. Gladden Deep is the first well of a four well infrastructure-led exploration program in the U.S. Gulf of Mexico planned in 2019.

In August 2019, we entered into a letter of intent for a cross assignment of our interest in Mississippi Canyon Block 728 with Hess Corporation on their interest in an adjacent block, Mississippi Canyon Block 684, after which Kosmos will have a 40% interest in the two blocks, and Hess Corporation having a 60% interest.

Greater Tortue Ahmeyim Unit

In April 2019, KBR was awarded the Pre-FEED services contract for Phases 2 and 3 of the Greater Tortue Ahmeyim project. These next phases are expected to expand capacity of this hub to almost 10 MMTPA of LNG for export.

During the second quarter of 2019, the National Oil Companies in Mauritania and Senegal 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%.

In July 2019, we announced 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.

Mauritania

In the second quarter of 2019, we withdrew from Block C18 offshore Mauritania.

In the second quarter of 2019, we entered into the second exploration phase on blocks C8 and C12 offshore Mauritania, each of which expire in June 2022. Block C12 contains a one well drilling commitment.

Equatorial Guinea

Production in Equatorial Guinea averaged approximately 40,900 Bopd gross in the second quarter of 2019. Our ESP program is supporting field production with the first installation of three ESPs completed during the first half of 2019. We expect to complete two more ESP conversions beginning in the third quarter of 2019.

Republic of the Congo

In March 2019, we entered into a petroleum contract covering the offshore Marine XXI block with the Republic of the Congo, subject to customary governmental approvals. Upon approval, we will hold an 85% participating interest and are the operator. The Congolese national oil company, SPNC, has a 15% carried participating interest during the exploration period. Should a commercial discovery be made, SNPC's 15% carried interest will convert to a participating interest of at least 15%. The petroleum contract covers approximately 2,350 square kilometers, with a first exploration period of four years and include a work program to acquire and interpret 2,200 square kilometers of 3D seismic. There are two optional exploration phases, each for a period of three years, which are subject to additional work program commitments.

Sao Tome and Principe

In May 2019, we entered into the second exploration phase on Block 5 offshore Sao Tome and Principe, which contains a one well drilling commitment and expires in May 2021. Galp Energia Sao Tome e Principe Unipessoal, provided notice of withdrawal at the same time, resulting in an increase in Kosmos participating interest from 45% to 58.8%.

In May 2019, we entered into a farm-out agreement with Shell Sao Tome and Principe B.V. to farmout a 20% participating interest in Block 6 and a 30% participating interest in Block 11, offshore Sao Tome and Principe, subject to customary governmental approvals.

In July 2019, we amended the petroleum contract for Block 11 offshore Sao Tome and Principe to remove any well commitment from the second exploration phase and added a contingent well to the third exploration phase in addition to the existing firm well. We also entered the second exploration phase which will expire in August 2021.

Namibia

In the second quarter, we received government approval to enter the second renewal period on block PEL039 offshore Namibia, which contains a one well drilling commitment. We also received a one year extension to the phase, resulting in a three year period ending in August 2022.

Republic of South Africa

During the first quarter of 2019, we executed 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, subject to customary governmental approvals. 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.

Results of Operations

All of our results, as presented in the table below, represent operations from 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 three and six months ended June 30, 2019 and 2018 are included in the following tables:

	Three Months Ended June 30, 2019	Six Months Ended June 30, 2019
	(In thousands, except per volume data)	
Sales volumes:		
Oil (MBbl)	5,851	10,541
Gas (MMcf)	1,663	3,464
NGL (MBbl)	139	251
Total (MBoe)	6,267	11,369
Revenues:		
Oil sales	$ 389,286	$ 680,150
Gas sales	4,145	7,807
NGL sales	2,502	4,766
Total revenues	$ 395,933	$ 692,723
Average oil sales price per Bbl	$ 66.53	$ 64.52
Average gas sales price per Mcf	2.49	2.25
Average NGL sales price per Bbl	18.01	18.96
Average total sales price per Boe	63.18	60.93
Costs:		
Oil and gas production, excluding workovers	$ 85,351	$ 158,066
Oil and gas production, workovers	5,626	12,710
Total oil and gas production costs	$ 90,977	$ 170,776
Depletion, depreciation and amortization	$ 151,438	$ 269,533
Average cost per Boe:		
Oil and gas production, excluding workovers	$ 13.62	$ 13.90
Oil and gas production, workovers	0.90	1.12
Total oil and gas production costs	14.52	15.02
Depletion, depreciation and amortization	24.16	23.71
Oil and gas production cost and depletion costs	$ 38.68	$ 38.73

	Three Months Ended June 30, 2018			Six Months Ended June 30, 2018		
	Kosmos	Equity Method Investment - Equatorial Guinea(1)	Total	Kosmos	Equity Method Investment - Equatorial Guinea(1)	Total
	(In thousands, except per volume data)					
Sales volumes:						
Oil (MBbl)	2,895	950	3,845	4,829	2,830	7,659
Gas (MMcf)	—	—	—	—	—	—
NGL (MBbl)	—	—	—	—	—	—
Total (MBoe)	2,895	950	3,845	4,829	2,830	7,659
Revenues:						
Oil sales	$ 215,191	$ 69,198	$ 284,389	$ 342,387	$ 192,375	$ 534,762
Gas sales	—	—	—	—	—	—
NGL sales	—	—	—	—	—	—
Total revenues	$ 215,191	$ 69,198	$ 284,389	$ 342,387	$ 192,375	$ 534,762
Average oil sales price per Bbl	$ 74.32	$ 72.84	$ 73.96	$ 70.90	$ 67.98	$ 69.82
Average gas sales price per Mcf	—	—	—	—	—	—
Average NGL sales price per Bbl	—	—	—	—	—	—
Average total sales price per Boe	74.32	72.84	73.96	70.90	67.98	69.82
Costs:						
Oil and gas production, excluding workovers	$ 51,894	$ 11,666	$ 63,560	$ 94,154	$ 37,516	$ 131,670
Oil and gas production, workovers	(2,079)	—	(2,079)	2,429	—	2,429
Total oil and gas production costs	$ 49,815	$ 11,666	$ 61,481	$ 96,583	$ 37,516	$ 134,099
Depletion, depreciation and amortization	$ 74,289	$ 24,574	$ 98,863	$ 128,566	$ 78,572	$ 207,138
Average cost per Boe:						
Oil and gas production, excluding workovers	$ 17.93	$ 12.28	$ 16.53	$ 19.51	$ 13.26	$ 17.19
Oil and gas production, workovers	(0.72)	—	(0.54)	0.50	—	0.32
Total oil and gas production costs	17.21	12.28	15.99	20.01	13.26	17.51
Depletion, depreciation and amortization	25.66	25.87	25.71	26.61	27.76	27.05
Oil and gas production cost and depletion costs	$ 42.87	$ 38.15	$ 41.70	$ 46.62	$ 41.02	$ 44.56

(1) For the three and six months ended June 30, 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 following table shows the number of wells in the process of being drilled or in active completion stages, and the number of wells suspended or waiting on completion as of June 30, 2019:

	Actively Drilling or Completing				Wells Suspended or Waiting on Completion			
	Exploration		Development		Exploration		Development	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Ghana								
Jubilee Unit	—	—	1	0.24	—	—	9	2.17
TEN	—	—	1	0.17	—	—	6	1.02
Deepwater Tano	—	—	—	—	—	—	—	—
U.S. Gulf of Mexico								
Nearly Headless Nick	—	—	—	—	1	0.22	—	—
Odd Job 214#2	—	—	—	—	—	—	1	0.61
Gladden Deep	1	0.20	—	—	—	—	—	—
Mauritania								
C8	—	—	1	0.28	4	1.12	—	—
Senegal								
Saint Louis Offshore Profond	—	—	—	—	1	0.30	—	—
Cayar Profond	—	—	—	—	3	0.90	—	—
Total	1	0.20	3	0.69	9	2.54	16	3.80

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.

Three months ended June 30, 2019 compared to three months ended June 30, 2018

	Three Months Ended June 30, 2019	Three Months Ended June 30, 2018	Increase (Decrease)
		(In thousands)	
Revenues and other income:			
Oil and gas revenue	$ 395,933	$ 215,191	$ 180,742
Other income, net	1	282	(281)
Total revenues and other income	395,934	215,473	180,461
Costs and expenses:			
Oil and gas production	90,977	49,815	41,162
Facilities insurance modifications, net	2,278	1,029	1,249
Exploration expenses	29,905	77,481	(47,576)
General and administrative	28,072	17,497	10,575
Depletion, depreciation and amortization	151,438	74,289	77,149
Interest and other financing costs, net	59,803	18,870	40,933
Derivatives, net	(14,185)	140,272	(154,457)
(Gain) loss on equity method investment, net	—	(16,100)	16,100
Other expenses, net	(1,793)	938	(2,731)
Total costs and expenses	346,495	364,091	(17,596)
Income (loss) before income taxes	49,439	(148,618)	198,057
Income tax expense (benefit)	32,602	(45,345)	77,947
Net income (loss)	$ 16,837	$ (103,273)	$ 120,110

Oil and gas revenue. Oil and gas revenue increased by $180.7 million primarily as a result of the inclusion of revenue from our U.S. Gulf of Mexico business unit during the three months ended June 30, 2019 related to the DGE acquisition, which was completed during the third quarter of 2018 and the inclusion of revenue from Equatorial Guinea on a consolidated basis for the three months ended June 30, 2019, which was previously accounted for as an equity method investment. The revenue increases from higher sales volumes was impacted by lower oil prices during the three months ended June 30, 2019, compared to the three months ended June 30, 2018. We sold 6,267 MBoe at an average realized price per barrel equivalent of $63.18 during the three months ended June 30, 2019 and 2,895 MBoe at an average realized price per barrel equivalent of $74.32 during the three months ended June 30, 2018.

Oil and gas production. Oil and gas production costs increased by $41.2 million during the three months ended June 30, 2019, as compared to the three months ended June 30, 2018. This is primarily a result of the inclusion of the U.S. Gulf of Mexico business unit during the three months ended June 30, 2019, related to the DGE acquisition, which was completed during the third quarter of 2018 and the inclusion of Equatorial Guinea on a consolidated basis for the three months ended March 31, 2019, which was previously accounted for as an equity method investment.

Facilities insurance modifications, net. During the three months ended June 30, 2019, we incurred $11.2 million of facilities insurance modifications costs associated with the long-term solution to the Jubilee turret bearing issue versus $9.5 million during the three months ended June 30, 2018. During the three months ended June 30, 2019 and 2018, these costs were offset by $8.9 million and $8.4 million, respectively, of hull and machinery insurance proceeds.

Exploration expenses. Exploration expenses decreased by $47.6 million during the three months ended June 30, 2019, as compared to the three months ended June 30, 2018. The decrease is primarily a result of unsuccessful well costs recorded in 2018 associated with our Suriname drilling.

General and administrative. General and administrative costs increased by $10.6 million during the three months ended June 30, 2019, as compared with the three months ended June 30, 2018. The increase is driven primarily by inclusion of our U.S. Gulf of Mexico business unit related to the DGE acquisition, which occurred during the third quarter of 2018.

Depletion, depreciation and amortization. Depletion, depreciation and amortization increased $77.1 million during the three months ended June 30, 2019, as compared with the three months ended June 30, 2018. The increase is primarily a result of depletion and depreciation costs associated with the acquired U.S. Gulf of Mexico properties and Equatorial Guinea business unit, which was previously accounted for as an equity method investment.

Interest and other financing costs, net. Interest and other financing costs, net increased $40.9 million primarily a result of an increased outstanding debt balance, the result of the DGE acquisition during the third quarter of 2018, and a $24.8 million loss on extinguishment of debt primarily associated with the refinancing of our senior notes recorded during the second quarter of 2019.

Derivatives, net. During the three months ended June 30, 2019 and 2018, we recorded a gain of $14.2 million and a loss of $140.3 million, respectively, on our outstanding hedge positions. The amounts recorded were a result of changes in the forward oil price curve during the respective periods.

(Gain) loss on equity method investment, net. During the three months ended June 30, 2018 we recognized an $16.1 million gain on our equity method investment in KTIPI. Effective January 1, 2019, our equity method investment in KTIPI was exchanged for a direct interest in the Ceiba Field and Okume Complex, which was accounted for under the proportionate consolidation method of accounting during the three months ended June 30, 2019.

Income tax expense (benefit). For the three months ended June 30, 2019, our overall effective tax rate was impacted by the difference in our 21% U.S. income tax reporting rate and the 35% statutory tax rates applicable to our Ghanaian and Equatorial Guinean operations, non-deductible and non-taxable items associated with our U.S., Ghanaian, and Equatorial Guinean operations, and other losses and expenses, primarily related to 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 expenses or losses.

For the three months ended June 30, 2018, our overall effective tax rate was impacted by non-deductible and non-taxable items associated with our U.S. and Ghanaian operations and other losses and expenses, primarily related to 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 expenses or losses.

Six months ended June 30, 2019 compared to six months ended June 30, 2018

	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018	Increase (Decrease)
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	$ 692,723	$ 342,387	$ 350,336
Other income, net	1	263	(262)
Total revenues and other income	692,724	342,650	350,074
Costs and expenses:			
Oil and gas production	170,776	96,583	74,193
Facilities insurance modifications, net	(17,743)	9,478	(27,221)
Exploration expenses	60,249	98,674	(38,425)
General and administrative	63,980	39,380	24,600
Depletion, depreciation and amortization	269,533	128,566	140,967
Interest and other financing costs, net	94,844	44,564	50,280
Derivatives, net	62,900	178,750	(115,850)
(Gain) loss on equity method investment, net	—	(34,796)	34,796
Other expenses, net	326	4,643	(4,317)
Total costs and expenses	704,865	565,842	139,023
Income (loss) before income taxes	(12,141)	(223,192)	211,051
Income tax expense (benefit)	23,928	(69,693)	93,621
Net income (loss)	$ (36,069)	$ (153,499)	$ 117,430

Oil and gas revenue. Oil and gas revenue increased by $350.3 million primarily as a result of the inclusion of revenue from our U.S. Gulf of Mexico business unit during the six months ended June 30, 2019 related to the DGE acquisition, which was completed during the third quarter of 2018 and the inclusion of revenue from Equatorial Guinea on a consolidated basis for the six months ended June 30, 2019, which was previously accounted for as an equity method investment. The revenue increases from higher sales volumes was impacted by lower oil prices during the six months ended June 30, 2019, compared to the six months ended June 30, 2018. We sold 11,369 MBoe at an average realized price per barrel equivalent of $60.93 during the six months ended June 30, 2019 and 4,829 MBoe at an average realized price per barrel equivalent of $70.90 during the six months ended June 30, 2018.

Oil and gas production. Oil and gas production costs increased by $74.2 million during the six months ended June 30, 2019, as compared to the six months ended June 30, 2018. This is primarily a result of the inclusion of the U.S. Gulf of Mexico business unit during the six months ended June 30, 2019, related to the DGE acquisition, which was completed during the third quarter of 2018 and the inclusion of revenue from Equatorial Guinea on a consolidated basis for the six months ended June 30, 2019, which was previously accounted for as an equity method investment.

Facilities insurance modifications, net. During the six months ended June 30, 2019, we incurred $22.2 million of facilities insurance modifications costs associated with the long-term solution to the Jubilee turret bearing issue versus $19.2 million during the six months ended June 30, 2018. During the six months ended June 30, 2019 and 2018, these costs were offset by $39.9 million and $9.7 million, respectively, of hull and machinery insurance proceeds.

Exploration expenses. Exploration expenses decreased by $38.4 million during the six months ended June 30, 2019, as compared to the six months ended June 30, 2018. The decrease is primarily a result of unsuccessful well costs recorded in 2018 associated with our Suriname drilling in 2018.

General and administrative. General and administrative costs increased by $24.6 million during the six months ended June 30, 2019, as compared with the six months ended June 30, 2018. The increase is driven primarily by our U.S. Gulf of Mexico business unit related to the DGE acquisition, which occurred during the third quarter of 2018.

Depletion, depreciation and amortization. Depletion, depreciation and amortization increased $141.0 million during the six months ended June 30, 2019, as compared with the six months ended June 30, 2018. The increase is primarily a result of depletion and depreciation costs associated with the acquired U.S. Gulf of Mexico properties and Equatorial Guinea business unit, which was previously accounted for as an equity method investment.

Interest and other financing costs, net. Interest and other financing costs, net increased $50.3 million primarily a result of an increased outstanding debt balance, the result of the DGE acquisition during the third quarter of 2018, and a $24.8 million loss on extinguishment of debt primarily associated with the refinancing of our senior notes recorded during the second quarter of 2019.

Derivatives, net. During the six months ended June 30, 2019 and 2018, we recorded a loss of $62.9 million and a loss of $178.8 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.

(Gain) loss on equity method investment, net. During the six months ended June 30, 2018 we recognized an $34.8 million gain on our equity method investment in KTIPI. Effective January 1, 2019, our equity method investment in KTIPI was exchanged for a direct interest in the Ceiba Field and Okume Complex, which was accounted for under the proportionate consolidation method of accounting during the six months ended June 30, 2019.

Other expenses, net. Other expenses, net decreased $4.3 million primarily related to disputed charges of $3.0 million related to the arbitration against Tullow Ghana.

Income tax expense (benefit). For the six months ended June 30, 2019, our overall effective tax rate was impacted by the difference in our 21% U.S. income tax reporting rate and the 35% statutory tax rates applicable to our Ghanaian and Equatorial Guinean operations, non-deductible and non-taxable items associated with our U.S., Ghanaian, and Equatorial Guinean operations, and other losses and expenses, primarily related to 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 expenses or losses.

For the six months ended June 30, 2018, our overall effective tax rate was impacted by non-deductible and non-taxable items associated with our U.S. and Ghanaian operations and other losses and expenses, primarily related to 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 expenses or losses.

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.

While we are presently in a strong financial position, commodity prices are volatile and could negatively impact our ability to generate sufficient operating cash flows to meet our funding requirements. To partially mitigate this price volatility, we maintain a hedging program. Our investment decisions are based on longer-term commodity prices based on the long-term nature of our projects and development plans. Also, BP has agreed to partially carry our exploration, appraisal and development program in Mauritania and Senegal up to a contractually agreed cap. Current commodity prices, combined with our hedging program, partner carries and our current liquidity position support our dividend and remaining capital program for 2019.

Sources and Uses of Cash

The following table presents the sources and uses of our cash and cash equivalents and restricted cash for the six months ended June 30, 2019 and 2018:

	Six Months Ended June 30,	
	2019	2018
	(In thousands)	
Sources of cash, cash equivalents and restricted cash:		
Net cash provided by operating activities	$ 222,390	$ 433
Net proceeds from issuance of senior notes	641,875	—
Return of investment from KTIPI	—	79,970
Borrowings under long-term debt	175,000	—
	1,039,265	80,403
Uses of cash, cash equivalents and restricted cash:		
Oil and gas assets	153,268	92,650
Other property	5,230	2,815
Payments on long-term debt	300,000	100,000
Redemption of senior secured notes	535,338	—
Purchase of treasury stock	1,983	17,695
Dividends	36,289	—
Deferred financing costs	1,981	25,743
	1,034,089	238,903
Increase (decrease) in cash, cash equivalents and restricted cash	$ 5,176	$ (158,500)

Net cash provided by operating activities. Net cash provided by operating activities for the six months ended June 30, 2019 was $222.4 million compared with net cash provided by operating activities for the six months ended June 30, 2018 of $0.4 million. The increase in cash provided by operating activities is primarily a result of the inclusion of our U.S. Gulf of Mexico business unit during the six months ended June 30, 2019 related to the DGE acquisition, which was completed during the third quarter of 2018 and the inclusion of operations from Equatorial Guinea on a consolidated basis for the six months ended June 30, 2019, which was previously accounted for as an equity method investment.

The following table presents our net debt and liquidity as of June 30, 2019:

	June 30, 2019
	(In thousands)
Cash and cash equivalents	$ 176,908
Restricted cash	7,901
Senior Notes at par	650,000
Borrowings under the Facility	1,500,000
Borrowings under the Corporate Revolver	25,000
Net debt	$ 1,990,191
Availability under the Facility	$ 100,000
Availability under the Corporate Revolver	$ 375,000
Available borrowings plus cash and cash equivalents	$ 651,908

Capital Expenditures and Investments

We expect to incur capital costs as we:

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

We have relied on a number of assumptions in budgeting for our future activities. These include the number of wells we plan to drill, our participating, 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, environmental and competitive uncertainties, contingencies and risks, all of which are difficult to predict and many of which are beyond our control. We may need to raise additional funds more quickly if market conditions deteriorate; or one or more of our assumptions proves to be incorrect or if we choose to expand our acquisition, exploration, appraisal, development efforts or any other activity more rapidly than we presently anticipate. We may decide to raise additional funds before we need them if the conditions for raising capital are favorable. We may seek to sell equity or debt securities or obtain additional bank credit facilities. The sale of equity securities could result in dilution to our shareholders. The incurrence of additional indebtedness could result in increased fixed obligations and additional covenants that could restrict our operations.

2019 Capital Program

We estimate we will spend approximately $425-$475 million of capital, net of carry amounts related to the Mauritania and Senegal transactions with BP, for the year ending December 31, 2019. However, the ultimate amount of capital we will spend may vary or fluctuate materially based on market conditions and the success of our drilling results among other factors. Through June 30, 2019, we have spent approximately $211 million.

Significant Sources of Capital

Facility

In February 2018, the Company amended and restated the Facility with a total commitment of $1.5 billion from a number of financial institutions with additional commitments up to $0.5 billion being available if the existing financial institutions increase their commitments or if commitments from new financial institutions are added. The borrowing base calculation includes value related to the Jubilee, TEN, Ceiba and Okume fields. In March 2019, following the lender's annual redetermination, the available borrowing base under our Facility was limited to the Facility size of $1.7 billion. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities. As part of the debt refinancing in February 2018, the repayment of borrowings under the existing facility attributable to financial institutions that did not participate in the amended Facility was accounted for as an extinguishment of debt, and $4.1 million of existing unamortized debt issuance costs and deferred interest attributable to those participants was expensed in interest and other financing costs, net in the first quarter of 2018. As of June 30, 2019, we have $35.9 million of unamortized issuance costs related to the Facility, which will be amortized over the remaining term of the Facility. The commitments were reduced by $100 million to $1.6 billion following the Senior Notes issuance in April 2019.

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 June 30, 2019, we had no letters of credit issued under the Facility.

We were in compliance with the financial covenants contained in the Facility as of March 31, 2019 (the most recent assessment date). The Facility contains customary cross default provisions.

Corporate Revolver

In August 2018, we amended and restated the Corporate Revolver from a number of financial institutions, maintaining the borrowing capacity at $400.0 million, extending the maturity date from November 2018 to May 2022 and lowering the margin 100 basis points to 5%. This 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 June 30, 2019, borrowings under the Corporate Revolver totaled $25 million and the undrawn availability under the Corporate Revolver was $375 million. We were in compliance with the financial covenants contained in the Corporate Revolver as of March 31, 2019 (the most recent assessment date). The Corporate Revolver contains customary cross default provisions.

Revolving Letter of Credit Facility

We had a revolving letter of credit facility agreement (“LC Facility”), which matured in July 2019. In July 2018, the LC Facility size was voluntarily reduced to $20.0 million based on the expiration of several large outstanding letters of credit. As of June 30, 2019, there were six outstanding letters of credit totaling $9.4 million under the LC Facility. The LC Facility contains customary cross default provisions.

In June 2019, we issued a $17.0 million letter of credit under a new letter of credit arrangement, which does not require cash collateral. This arrangement contains customary cross default provisions.

7.875% Senior Secured Notes due 2021

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

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

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 during the second quarter.

7.125% Senior Notes due 2026

In April 2019, the Company issued $650.0 million of 7.125% Senior Notes (the "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 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.

Contractual Obligations

The following table summarizes by period the payments due for our estimated contractual obligations as of June 30, 2019:

	Payments Due By Year(4)						
	Total	2019(5)	2020	2021	2022	2023	Thereafter
	(In thousands)						
Principal debt repayments(1)	$ 2,175,000	$ —	$ —	$ 274,800	$ 309,200	$ 271,600	$ 1,319,400
Interest payments on long-term debt(2)	654,775	67,968	128,609	118,677	105,986	88,771	144,764
Operating leases(3)	37,039	1,100	4,699	3,895	3,918	3,907	19,520

(1) Includes the scheduled principal maturities for the $650.0 million aggregate principal amount of Senior Notes issued in April 2019, borrowings under the Facility and the Corporate Revolver. The scheduled maturities of debt related to the Facility are based on, as of June 30, 2019, our level of borrowings and our estimated future available borrowing base commitment levels in future periods. Any increases or decreases in the level of borrowings or increases or decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter.

(2) Based on outstanding borrowings as noted in (1) above and the LIBOR yield curves at the reporting date and commitment fees related to the Facility and Corporate Revolver and the interest on the Senior Secured 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 15 — Additional Financial Information for additional information regarding these liabilities.

(5) Represents the period from July 1, 2019 through December 31, 2019.

We currently have a commitment to drill one exploration well in each of Sao Tome and Principe and Namibia and two exploration wells in each of Mauritania and Senegal. In Mauritania and Senegal, BP is obligated to fund our share of the cost of the exploration wells, subject to the remaining exploration and appraisal carry covering our Mauritania and Senegal blocks. In Sao Tome and Principe, we also have 3D seismic acquisition requirements of approximately 13,500 square kilometers. In South Africa, subject to customary governmental approvals, we have 2D seismic acquisition requirements of approximately 500,000 line kilometers.

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

	Years Ending December 31,						Asset (Liability) Fair Value at June 30,
	2019(3)	2020	2021	2022	2023	Thereafter	2019
	(In thousands, except percentages)						
Fixed rate debt:							
Senior Secured Notes	$ —	$ —	$ —	$ —	$ —	$ 650,000	$ (656,422)
Fixed interest rate	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	
Variable rate debt:							
Facility(1)	$ —	$ —	$ 274,800	$ 284,200	$ 271,600	$ 669,400	$ (1,500,000)
Corporate Revolver	—	—	—	25,000	—	—	(25,000)
Weighted average interest rate(2)	5.32%	4.86%	4.78%	5.16%	5.38%	6.00%	

(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 June 30, 2019. Any increases or decreases in the level of borrowings or increases or decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter.

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

(3) Represents the period July 1, 2019 through December 31, 2019.

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 June 30, 2019, our material 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

We consider accounting policies related to our revenue recognition, exploration and development costs, receivables, income taxes, derivative instruments and hedging activities, estimates of proved oil and natural gas reserves, asset retirement obligations, leases and impairment of long-lived assets as critical accounting policies. The policies include significant estimates made by management using information available at the time the estimates are made. However, these estimates could change materially if different information or assumptions were used. Other than the implementation of the new lease standard discussed in Note 2 — Accounting Policies, there have been no changes to our critical accounting policies which are summarized in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" section in our annual report on Form 10-K, for the year ended December 31, 2018.

Cautionary Note Regarding Forward-looking Statements

This quarterly report on Form 10-Q contains estimates and forward-looking statements, principally in "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 quarterly report on Form 10-Q and our annual report on Form 10-K, may adversely affect our results as indicated in forward-looking statements. You should read this quarterly report on Form 10-Q, the annual report on Form 10-K and the documents that we have filed with the Securities and Exchange Commission completely and with the understanding that our actual future results may be materially different from what we expect. Our estimates and forward-looking statements may be influenced by the following factors, among others:

- our ability to find, acquire or gain access to other discoveries and prospects and to successfully develop and produce from our current discoveries and prospects;
- uncertainties inherent in making estimates of our oil and natural gas data;
- the successful implementation of our and our block partners' prospect discovery and development and drilling plans;
- projected and targeted capital expenditures and other costs, commitments and revenues;
- termination of or intervention in concessions, rights or authorizations granted to us by the governments of the countries in which we operate (or their respective national oil companies) or any other federal, state or local governments or authorities;
- our dependence on our key management personnel and our ability to attract and retain qualified technical personnel;
- the ability to obtain financing and to comply with the terms under which such financing may be available;
- the volatility of oil, natural gas and NGL prices;
- the availability, cost, function and reliability of developing appropriate infrastructure around and transportation to our discoveries and prospects;
- the availability and cost of drilling rigs, production equipment, supplies, personnel and oilfield services;
- other competitive pressures;
- potential liabilities inherent in oil and natural gas operations, including drilling and production risks and other operational and environmental risks and hazards;
- current and future government regulation of the oil and gas industry or regulation of the investment in or ability to do business with certain countries or regimes;
- cost of compliance with laws and regulations;
- changes in environmental, health and safety or climate change or greenhouse gas ("GHG") laws and regulations or the implementation, or interpretation, of those laws and regulations;
- adverse effects of sovereign boundary disputes in the jurisdictions in which we operate;
- environmental liabilities;
- geological, geophysical and other technical and operations problems, including drilling and oil and gas production and processing;
- military operations, civil unrest, outbreaks of disease, terrorist acts, wars or embargoes;
- the cost and availability of adequate insurance coverage and whether such coverage is enough to sufficiently mitigate potential losses and whether our insurers comply with their obligations under our coverage agreements;
- our vulnerability to severe weather events, including tropical storms and hurricanes in the Gulf of Mexico;
- our ability to meet our obligations under the agreements governing our indebtedness;
- the availability and cost of financing and refinancing our indebtedness;
- the amount of collateral required to be posted from time to time in our hedging transactions, letters of credit, performance bonds and other secured debt;
- the result of any legal proceedings, arbitrations, or investigations we may be subject to or involved in;

- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks; and
- other risk factors discussed in the “Item 1A. Risk Factors” section of this quarterly report on Form 10-Q and our 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 quarterly report on Form 10-Q 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.

Item 3. 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” section of our annual report on Form 10-K 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 six months ended June 30, 2019:

	Derivative Contracts Assets (Liabilities)	
	Commodities	
	(In thousands)	
Fair value of contracts outstanding as of December 31, 2018	$	30,744
Changes in contract fair value		(65,686)
Contract maturities		21,044
Fair value of contracts outstanding as of June 30, 2019	$	(13,898)

Commodity Price Risk

The Company’s revenues, earnings, cash flows, capital investments and, ultimately, future rate of growth are highly dependent on the prices we receive for our crude oil, which have historically been very volatile. Substantially all of our oil sales are indexed against Dated Brent, Eugene Island, Heavy Louisiana Sweet and Mars crude.

Commodity Derivative Instruments

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

Commodity Price Sensitivity

The following table provides information about our oil derivative financial instruments that were sensitive to changes in oil prices as of June 30, 2019. Volumes and weighted average prices are net of any offsetting derivatives entered into.

				Weighted Average Price per Bbl					Asset (Liability)
Term	Type of Contract	Index	MBbl	Net Deferred Premium Payable/(Receivable)	Swap	Sold Put	Floor	Ceiling	Fair Value at June 30, 2019(3)
									(In thousands)
2020:									
Jul — Dec	Three-way collars	Dated Brent	5,256	$ 1.17	$ —	$ 43.81	$ 53.33	$ 73.57	$ (8,582)
Jul — Dec	Sold calls(1)	Dated Brent	460	—	—	—	—	80.00	(4,723)
Jul — Dec	Swaps	NYMEX WTI	730	—	52.01	—	—	—	(4,420)
Jul — Dec	Collars	Argus LLS	500	—	—	—	60.00	88.75	1,293
2020:									
Jan — Dec	Three-way collars	Dated Brent	6,000	$ 0.45	$ —	$ 45.00	$ 57.50	$ 80.18	$ 8,283
Jan — Dec	Sold calls(1)(2)	Dated Brent	8,000	1.17	—	—	—	85.00	(5,749)

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

(2) Deferred premium payable to be paid July 1, 2019 — December 31, 2019.

(3) Fair values are based on the average forward oil prices on June 30, 2019.

In July 2019, we entered into put option contracts for 2.0 MMBbl from January 2020 through December 2020 with a floor price of $60.00 per barrel and a sold put price of $50.00 per barrel. In addition, we sold 1.0 MMBbl of calls from January 2021 through December 2021 with a strike price of $75.00 per barrel. The contracts are indexed to Dated Brent prices.

At June 30, 2019, our open commodity derivative instruments were in a net liability position of $13.9 million. As of June 30, 2019, a hypothetical 10% price increase in the commodity futures price curves would decrease future pre-tax earnings by approximately $40.1 million. Similarly, a hypothetical 10% price decrease would increase future pre-tax earnings by approximately $33.8 million.

Interest Rate Sensitivity

At June 30, 2019, we had indebtedness outstanding under the Facility of $1,500 million and the Corporate Revolver of $25 million, which bore interest at floating rates. The interest rate on this indebtedness as of June 30, 2019 was approximately 5.7% and 7.4%, respectively. If LIBOR increased by 10% at this level of floating rate debt, we would pay an additional $3.7 million in 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.

Item 4. 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 June 30, 2019, 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.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

There have been no material changes from the information concerning legal proceedings discussed in the “Item 3. Legal Proceedings” section of our annual report on Form 10-K.

Item 1A. Risk Factors

There have been no material changes from the risks discussed in the “Item 1A. Risk Factors” section of our annual report on Form 10-K for the year ended December 31, 2018, other than the following:

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 our outstanding debt.

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.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information.

There have been no material changes required to be reported under this Item that have not previously been disclosed in the annual report on Form 10-K.

Item 6. Exhibits

The information required by this Item 6 is set forth in the Index to Exhibits accompanying this quarterly report on Form 10-Q.

SIGNATURES

Pursuant to the requirements 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. (Registrant)
Date	August 5, 2019	/s/ THOMAS P. CHAMBERS
		Thomas P. Chambers Senior Vice President and Chief Financial Officer (Principal Financial Officer)

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INDEX OF EXHIBITS

Exhibit Number	Description of Document
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.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

Exhibit 31.1

Certification of Chief Executive Officer

I, Andrew G. Inglis, certify that:

1. I have reviewed this quarterly report on Form 10-Q 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: August 5, 2019

/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, Thomas P. Chambers, certify that:

1. I have reviewed this quarterly report on Form 10-Q 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: August 5, 2019

/s/ THOMAS P. CHAMBERS

Thomas P. Chambers
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 quarterly report of Kosmos Energy Ltd. (the “Company”) on Form 10-Q for the quarter ended June 30, 2019, 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: August 5, 2019	/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 accompanying quarterly report of Kosmos Energy Ltd. (the “Company”) on Form 10-Q for the quarter ended June 30, 2019, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Thomas P. Chambers, 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: August 5, 2019

/s/ THOMAS P. CHAMBERS

Thomas P. Chambers
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.